BWR OWNERS' GROUP

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SUBJECT: Responses to Requests for Additional Information (RAIs) Dated December 21, 2005 and April 20, 2006, Regarding the BWROG Topical Report NEDO-33148, "Separation of Loss of Offsite Power From Large Break LOCA [Loss-Of-Coolant Accident]" (TAC No. MC3042)

ENCLOSURES: (1) Responses to RAIs
(2) Outline of Revised Topical Report NEDO-33148
(3) Response to NRC Staff Comments on EPRI Double Sequencing Reports Related to BWROG LTR NEDO-33148

Dear Sir:

Enclosed please find the BWROG responses (Enclosure 1) to the NRC Requests for Additional Information (RAIs) on the subject Licensing Topical Report (LTR) NEDO-33148, along with an outline of the revised LTR (Enclosure 2), and responses to NRC staff comments on EPRI double sequencing reports related to this LTR (Enclosure 3). The RAIs for the thermal-hydraulic area were dated December 21, 2005; RAIs for the PRA and Electrical areas were dated April 20, 2006. The revised LTR itself will be provided by separate transmittal. The LTR reflect the outcome of our meetings with you on February 14, 2006, and June 14, 2006. At those meetings we agreed to provide a methodology document, rather than a bounding analysis, as the focus of the LTR. Finally, Enclosure 3 should be helpful in reviewing the BWROG responses to the RAIs in Enclosure 1.

We look forward to a timely NRC review and draft Safety Evaluation for the LTR to support the submittal of the lead plant licensing documents this fall.

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Should you have additional questions please contact Fred Emerson (BWROG Project Manager) at 910-675-5615 or Tony Browning (BWROG Option 3 Committee Chairman) at 319-851-7750.

Sincerely,

Joseph Conen

Joseph Conen
BWR Owners' Group Chairman

cc: Ms. Michelle Honcharik, NRC
Mr. Randy Bunt, Southern Nuclear Operating Company
Mr. Douglas Coleman, Energy Northwest
BWROG Primary Representatives
BWROG Option 3 Committee

Enclosure 1

Responses to NRC RAIs

Source	RAI #	Question	Response
PRA		**Scope of the TR**	
PRA	1	In at least one place (e.g., Page 10) the TR refers to LOCAs up to "large recirculation loop pipe breaks." In other places (e.g., Section 6.0) it refers to 10-inch and larger breaks. Please clarify the break size above which an exemption from the loss-of-offsite power (LOOP) will be requested by licensees. Do all seven options presented in the TR assume the same break size?	The T/H analysis demonstrated mitigation of a double-ended guillotine break of the largest pipe in the Reactor Recirculation system; this was applied consistently for all of the seven options. At the time the original LTR was written, the break size of 10 inches or greater corresponded in the published works to a frequency of 1.0 E-4/year, which when coupled with the conditional LOOP gives LOCA probability of 1.0 E-2, gave the target input probability of 1.0 E-6 for LBLOCA/LOOP. The revised topical will utilize the more recent references for LOCA frequencies, combined with plant-specific conditional LOOP probabilities given a LOCA, to determine the break sizes that will be redefined in the licensing basis. Based on the LOCA frequency values in NUREG 1829, certain plants may be able to justify exemption for break sizes of 7" diameter and above. Finally, all seven options presented in the TR would assume the same break size.

Source	RAI #	Question	Response
PRA		**Risk of LOOP with Large Break LOCA**	
PRA	2	The TR mentions References 2, 3, and 10 as the basis for the frequency of 1.0E-6 per year for the large break LOCA (LBLOCA) and LOOP combination. In addition, according to Figure C.4-1, the probability of LOOP given a LOCA is 1.0E-2. However, it is not clear how these two estimates are derived from the three references. Please explain how these two estimates have been derived and describe how a licensee would obtain plant-specific estimates of these two parameters.	EPRI developed the LOOP-Given-Large-LOCA probability using an expert elicitation process, described in Reference 10 of the original LTR. That reference recommends a best-estimate value of 1.0E-2 for this probability. The EPRI paper, which was never officially published, provides a detailed description of how this value was derived. The EPRI reference has not been used in the revised LTR. The conditional probability of LOOP given a LOCA is calculated in USNRC's, "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10 CFR 50.46/GDC 35," Revision 1, July 2002, This reference calculates the LOOP given LOCA probability for two plant configurations. The revised LTR recommends the use of these values for the plant-specific analysis. In addition, this reference provides a fault tree method for calculating a plant-specific value for the conditional LOOP given LOCA and this method is recommended in the revised LTR for licensees to calculate plant-specific values. This recommendation is especially useful for plants with multiple switchyards and multiple offsite power sources, as they will be able to calculate a lower value of LOOP given LOCA probability compared to other plants without this feature.

Source	RAI #	Question	Response
PRA	3	NUREG/CR-6538 studied Generic Safety Issue (GSI)-171, "ESF [Engineered Safety Feature] Failure from LOOP Subsequent to a LOCA." Specifically, Section 8.5.1 of NUREG/CR-6538 identified two plant-specific design features that could impact the probability that offsite power will be lost given a LOCA: the electrical switchyard associated with a plant having undervoltage for a significant fraction of time, and the energization scheme implemented to power the safety loads after a LOCA. In addition, for those plants that transfer the source of power feeding the safety buses after reactor trip, a failure of this transfer could cause a loss of power to these buses. Please describe how these potential vulnerabilities are accounted for in the development of the conditional probability of LOOP as a result of a LBLOCA.	EPRI developed the LOOP-Given-Large-LOCA probability using an expert elicitation process. The EPRI paper (Reference 10) presents, in great detail, the sequence of events that must occur to avoid a LOOP-Given-Large-LOCA. The 3 specific design features in this RAI are considered as follows: 1. Switchyard having under voltage a significant fraction of the time -- This condition would be a grid-centered factor included in the LOOP-Given-Trip probability of 0.003. The paper specifically considered transmission-provider contracts and communication protocols to determine the likelihood that such conditions would degrade in the future or that considerable variance exists from plant to plant. The experts concluded that neither of these situations is likely, although the report suggests performance monitoring to detect any adverse trends. 2. Energization scheme to power safety loads after LOCA – The energization scheme is considered in the system voltage analysis and in the plant setup to conform to the analysis. Errors in either of these processes are accounted for by assigning a latent human error probability. The plant-specific details of the energization scheme are not important to this probability estimation. The report notes that verifying consistency of the analysis and the plant set up should be a condition for implementing this risk-informed plant change. 3. Bus transfer after LOCA – This factor was explicitly considered in the EPRI paper. The experts concluded that there is no difference in the failure probability of this function whether there has been a LOCA or another trip. Therefore, these failure modes are included in the 0.003 LOOP-Given-Trip probability. For a plant that requires no bus transfers, the failure probability is slightly overestimated. The EPRI paper was never published officially, and the revised LTR does not use this EPRI reference for calculating the plant-specific LOOP given LOCA probability. See response to PRA RAI 2 also.

Source	RAI #	Question	Response
PRA	4	The TR states that "... The conditional loss of offsite power events (LOOP given LOCA and LOOP given transient) are modeled as grid centered events ..." The NRC staff notes that a consequential LOOP can also be due to plant-centered causes, such as failures in the switchyard. Please identify all the failure modes that could result in LOOP and define whether each failure is a grid-centered or plant-centered event. How will the potential for plant-centered causes of consequential LOOP be considered in the risk assessment?	The EPRI development of LOOP-Given-LOCA probability (see previous responses) considers grid-centered events and plant-centered events in detail. Generally, grid-centered events are adequately addressed by the database of LOOP-Given-Trip events in the industry. This value is 0.003. Plant-centered events are also addressed by that probability if, according to the experts, there is no difference in failure modes or likelihoods between the trip event and the LOCA event. Other plant-centered failure modes are explicitly considered in the EPRI paper including under-voltage transfers to EDGs from human errors and equipment failures. Five specific, plant-centered failures are quantified in the paper. The LTR modeled all consequential LOOPs as grid-centered because grid-centered events have the least credit for recovery of offsite power. The BWROG believes that this is a conservative approach. As noted in the response to PRA RAI 2 above, the revised LTR does not use the EPRI reference for evaluation of plant-specific LOOP given LOCA probability.

Source	RAI #	Question	Response
PRA		**Guidance on Plant-Specific Risk Assessment**	
PRA	5	Please describe generally how a licensee would demonstrate that its probabilistic risk assessment (PRA) satisfies Regulatory Guide (RG) 1.174 "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," guidelines regarding sufficient scope, level of detail, and technical acceptability commensurate with this application.	Regulatory Guide 1.200 addresses the use of the ASME PRA standard and the NEI peer review process (NEI 00-02) for evaluating PRA technical capability. In general, PRA quality has been enhanced through implementation of the MSPI. Plants implementing Option 3 will evaluate their PRAs in accordance with this regulatory guide. The RG specifically addresses the need to evaluate important assumptions that relate to key modeling uncertainties (such as common cause failure methods, success path determinations, human reliability assumptions, etc). Further, the RG addresses the need to evaluate parameter uncertainties and demonstrate that calculated risk metrics (e.g., CDF and LERF) represent mean values. The identified "Gaps" to Capability Category II requirements from the endorsed PRA standards in the RG and the identified key sources of uncertainty will be categorized into one of three categories: (1) Has no impact on risk assessment of Option 3 changes, or (2) Sensitivity cases need to be run to evaluate the impact on the Option 3 changes, or (3) "Gap" in PRA model needs to be addressed prior to using PRA model for Option 3 analysis. In the revised LTR, this process would not be necessary for a case where the qualitative review concludes that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact. (See Step 6). The selected plant modifications would be reflected in the Licensee's next scheduled PRA update.

Source	RAI #	Question	Response
PRA	6	Please describe generally what information a BWR licensee would submit to demonstrate that the five key principles stated in RG 1.174, Section 2 and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Section B are met.	The LTR was written to address the five key principles generically for BWROG licensees. In response to the RAIs, the document has been revised to more clearly address each of the five key principles. Each licensee will review the sections related to these principles and adjust the generic discussion to make it plant-specific for the licensee's submittal. The first principle, Compliance with Current Regulations, is addressed generically in Section 3.1 of the revised document. The second, Defense in Depth, is addressed in Section 3.2; the third, Safety Margins, is addressed in Section 3.3; the fourth, NRC Safety Goals, is addressed in Section 3.4; and the fifth, Monitoring Changes, is addressed in Section 3.5. An expanded version of this discussion would be included in each licensee's submittal.
PRA	7	Page 2 of Figure C.4-1 models conditional LOOP events (LOOP given LOCA and LOOP given transient) as part of grid-centered events. According to this figure, a LBLOCA and LOOP are linked with an "AND" gate together with the recovery of offsite power within one hour. In other words, solving the top gate for grid-centered events would yield the following cutset (among other cutsets): LBLOCA * LOOP * NR-LOOP-1HR where NR-LOOP-1HR is the failure to recover offsite power within one hour. This cutset does not appear realistic because a consequential LOOP would occur shortly after a LBLOCA, so the time available for recovery of offsite power is very short, and probably cannot be credited. Please describe how a licensee would be expected to model recovery of the consequential LOOP given a LBLOCA in their risk assessments. Describe and justify the use of any recovery of offsite power.	The logic presented in this figure is not called in the quantification of the large LOCA event tree. When quantifying the large LOCA tree, the BWROG used a version that did not include a recovery factor. The figure presented the base logic rather than all of the permutations. The BWROG reviewed the cutsets from the solutions and confirmed that none of the large LOCA scenarios include this recovery of offsite power. LOOPs following large break LOCAs are assumed to lead directly to core damage. Therefore, licensees need not model recovery of consequential LOOP given a large break LOCA.

Source	RAI #	Question	Response
PRA	8	Figures C.3-4 and C.4-1 present the LBLOCA event tree and fault tree for LOOP events, respectively. The event tree includes top events "TOP-LOSP2 (Offsite Power Available)" and "Recovery." The latter top event appears to be related to recovery of offsite power because the associated branches have the label "REC-LOSP-G6H." It appears that the LBLOCA event tree and fault tree for LOOP events are linked or combined in some way, but a description of the way they are linked was not found in the TR. Please describe in detail how a licensee would be expected to model the consequential LOOP event together with the LBLOCA event tree. The NRC staff notes that a consequential LOOP is likely to be delayed; i.e., not coincident with the LBLOCA. Please discuss in detail how a licensee would determine a plant-specific, best-estimate timing for the LOOP resulting from the LBLOCA, and how the delayed LOOP would be modeled in the PRA.	Although the logic model allowed for the possibility, there are no cutsets that actually reach the REC-LOSP-G6H branch (the conditional probability of TOP-LOSP2 failure is 0.0 for these branches on the large break LOCA event tree); therefore the large break LOCA and the 6-hour recovery factor are not combined in the solution of the event tree. This is because this branch is examined only in scenarios where initial injection is successful, and power must be available for initial injection to be successful. Offsite power recovery is examined only to determine the availability of containment heat removal. See the responses to PRA Question 4 (above) for a description of how the licensee would model recovery of consequential LOOP. Even though the BWROG refers to the LOCA/LOOP as being simultaneous events, in reality the LOOP could occur a few minutes after the LOCA and still be considered a LOCA/LOOP event. BWROG evaluation considers both the simultaneous and delayed (by a few minutes) events to lead to core damage. "A few minutes" is determined by the time for reflooding to occur. Any LOOP after the reflooding is not specifically modeled in the PRA and is not considered to be risk significant.

Source	RAI #	Question	Response
PRA	9	At the beginning of Section C.5, "Risk Calculation for Plant Changes," five steps to assess the impact on core damage frequency (CDF) and large early release frequency are presented. Please define the "base (unaltered case)," e.g., does it include the assumption that a LBLOCA and LOOP lead directly to core damage? Please provide more detail on each of the five steps.	The document has been revised to provide guidance on analyzing the Option 3 changes. The five steps mentioned here are all sub-steps within the step titled "Evaluate Risk Impact of Changes" in the revised document. The current generic PRA model does not include the assumption that large break LOCA/LOOP goes directly to core damage. Step 1 involves quantifying the "Base Case" PRA model with no changes. This version of the model does not include the assumption that Large Break LOCA with LOOP leads directly to core damage. Step 2 involves modifying the Base Case model to represent the change(s) (for example, allowing EDG warmup prior to loading) and including the assumption that Large Break LOCA with LOOP leads directly to core damage. Once the final combination of changes has been determined, the model created in Step 2 becomes the new plant PRA model. Step 2 also quantifies this model. Because the assumption that Large Break LOCA with LOOP is not included in the "Base Case" model, Step 3 is needed to remove the contribution from Large Break LOCA with LOOP that exists in the Step 2 model, but does not exist in the Base Case (Step 1) model to calculate an accurate change in risk resulting from the Option 3 change(s). Step 4 simply calculates the risk decrease (or increase) due to the change by subtracting the Base Case results from the Step 3 results (Step 2 results less any contribution from Large Break LOCA and LOOP). Step 5 just does a calculation similar to Steps 1 thru 4, except the value calculated is the change in LERF. Please see the response to PRA RAI 5 also which points out that in the revised LTR, no quantitative PRA evaluation is done if the qualitative evaluations show the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact.

Source	RAI #	Question	Response
PRA	10	Section C.6.2, "Sensitivity Analyses" does not address the generic probability of LOOP given a LOCA, or the generic frequency of a LBLOCA and LOOP. Please describe how the licensee would be expected to develop this information on a plant-specific basis and to address the uncertainty in the frequency of a LBLOCA and in the conditional probability of LOOP given a LBLOCA?	The revised guidance document provides possible values for LBLOCA frequency and for the conditional probability of LOOP given a LOCA. Uncertainty distribution parameters are provided for these values. LBLOCA frequencies from NUREG-1829, "Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process," and from NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995" are provided in the revised LTR. The conditional probability of LOOP given a LOCA is calculated in USNRC's, "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10 CFR 50.46/GDC 35," Revision 1, July 2002, This reference calculates the LOOP given LOCA probability for two plant configurations. The revised LTR recommends the use of these values for the plant-specific analysis. In addition, this reference provides a fault tree method for calculating a plant-specific value for the conditional LOOP given LOCA and this method is recommended in the revised LTR for licensees to calculate plant-specific values. This recommendation is especially useful for plants with multiple switchyards and multiple offsite power sources, as they will be able to calculate a lower value of LOOP given LOCA probability compared to other plants without this feature.
PRA		**Enabled Changes**	
PRA	11	Please describe how a licensee would assess the risk impact of adopting multiple options presented in the TR. To what extent, and in what manner, would the licensee evaluate the cumulative risk impact from changes made possible by an exemption to the regulations as requested in the TR?	The BWROG expects each licensee to evaluate the risk impact from each potential change individually. In the revised LTR, a qualitative evaluation, which includes thermal-hydraulic analysis, will be performed for each proposed modification. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. The other modifications will be modeled in the PRA. The results of both the qualitative and quantitative evaluations will aid the licensee in determining which changes to include in the request. Once the specific changes have been selected, an assessment will be made to determine if any additional thermal hydraulic analysis is needed. Then, the combination of all selected changes modeled individually in the PRA will be made in the PRA model and the combined risk impact quantified. This may produce results that lead to another iteration on the selection of changes to include and another quantification of overall risk impact.

Source	RAI #	Question	Response
PRA		**3.1 Allow Emergency Diesel Generator Warm Up Prior to Loading**	
PRA	12	Section 3.1 states that fast starting of emergency diesel generators (EDGs) decreases their reliability and increases their unavailability. It states that a warm up of 30 to 60 seconds would increase reliability. It further states that many maintenance outages are focused on degradation associated with fast starts. Please provide the technical basis for the claim that 30 to 60 seconds warm up will increase reliability, including data that supports the statement that "many" EDG maintenance outages are attributable to diesel fast starts. Alternately, state how a licensee would determine the appropriate increases in reliability and availability for a plant-specific risk assessment.	There is little data to quantitatively prove that slower starts will increase reliability. EDG experts believe that further elimination of fast starts can improve reliability, but cannot easily provide a number. NRC requested in NRC Generic Letter 84-15 and NRC Information Notice 85-32 that plants consider steps to reduce fast starts. We have eliminated fast starts from testing programs, and a portion of the overall improvement in DG reliability has resulted from these steps, but unplanned starts are still fast starts. It makes sense to further reduce the number of unplanned fast starts by eliminating the fast start logic. EDG fast starts require that the EDG reach rated speed within nominally, 10 seconds. There is a potential for material wear by low-cycle fatigue (LCF) during the fast startup as a result of initial maldistribution of the lube oil within the engine parts. Another functional failure could be related to failure to fast start within 10 seconds even though the unit managed to start and run (say, in 11 seconds). Should this happen, the test is repeated (following attempts to correct the offending condition) until the EDG finally passes the fast start test. This leads to material wear and EDG unavailability during the maintenance and subsequent retest. The revised LTR calls for a qualitative evaluation to be performed for each proposed modifications. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. We believe that elimination of EDG fast starts would not require a PRA quantification to be performed as part of individual plant submittals.

Source	RAI #	Question	Response
PRA		**3.2 Optimize the Loads Sequenced on to the EDGs**	
PRA	13	Section 3.2 states: "If the requirement for automatic loading of all LPCI [low pressure coolant injection] pumps or LPCS [low pressure core spray] pumps onto the diesel generators were eliminated, licensees would perform analyses to determine which equipment would be most beneficial to have automatically loaded." Please describe how a licensee could determine which loads would be beneficial and how it would evaluate the change in risk for a proposed change in EDG loading.	Plants should determine the proper loads and loading sequence from PRA dominant sequences and operator action importance measures related to manual loading of post-transient equipment, and consistency with existing plant operating and emergency procedures. An example of this equipment is battery chargers (as discussed in the LTR).
PRA		**3.3 Start EDGs Only When Needed**	
PRA	14	Section 3.3 states that one of the safety benefits of revising the EDG start logic "... *comes from the reduction of operator* burden following accidents and transients." Please describe how a licensee would model this proposed change in their PRA model, or otherwise assess the risk of the proposed change in an acceptable manner.	The revised LTR calls for a qualitative evaluation to be performed for each proposed modifications. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. We believe that the reduction of operator burden would not require a PRA quantification to be performed as part of individual plant submittals. If the utility still wants to quantify this improvement through the use of PRA, the following approach may be used. The licensee would first review its PRA model to determine which operator actions might be impacted by a reduction in operator burden. An initial list of operator actions to consider will be assembled by collecting all operator actions with a Fussel-Vesely importance greater than $1x10^{-3}$. This list will be screened to reduce the list to actions that could be impacted by the Option 3 change. For these operator actions, the attributes affecting the operator failure rate (performance shaping factors) such as stress level, time available to perform action, concurrent actions, and complexity of action would be reviewed to assess the impact of this change. The human reliability analysis (HRA) would then be reevaluated for the selected actions and the revised HRA values would be input to the PRA model. The revised LTR provides guidelines on how to revise the HRA values.

Source	RAI #	Question	Response
PRA	15	Section 3.3 says that eliminating the anticipatory starting of the EDGs increases diesel availability and reliability, because spurious starts will be reduced. Provide data regarding the number of spurious EDG starts that have occurred that are attributable to emergency core cooling system starting logic and justify the expected improvement in this frequency and provide justification for any improvement in EDG reliability assumed as the result of implementing this change. Alternately, state how a licensee would determine the appropriate increases in reliability and availability for a plant-specific risk assessment.	There is insufficient data to quantify the benefit of eliminating the anticipatory starts because there have been very few failure events due to anticipatory starts. However, on a qualitative basis, eliminating these starts will have a small positive effect on both unavailability and reliability, based on discussions with EDG experts. Given the elimination of large LOCA-LOOP scenarios from the licensing basis (based on CDF being negligible or other reasons), there is no benefit from retaining anticipatory starts in the start logic (gets rid of spurious starts). This eliminates having to correct failures from spurious starts. A review of 37 LERs listed in NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," Table A-2 for unplanned EDG demands during critical operation that were not identified as a loss of offsite power, from 1999 through 2003 (1998 LERs not readily available) yielded no events related to ECCS LOCA signals. The recommendation in the LTR is to remove the logic that starts the EDGs on a LOCA alone and only start them when there is an actual undervoltage or LOOP. Any fast start is believed to have a detrimental effect on EDG reliability, as described in NRC Generic Letter 84-15 and NRC Information Notice 85-32. This would eliminate unnecessary fast starts of the EDGs due to both spurious LOCA signals and actual LOCAs, if offsite power remained available. Even though it is believed that these events are fairly rare, eliminating these fast starts will have a positive effect on EDG reliability, however small that improvement might be. The revised LTR calls for a qualitative evaluation to be performed for each proposed modifications. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. We believe that elimination of the anticipatory starts of the EDGs would not require a PRA quantification to be performed as part of individual plant submittals.

Source	RAI #	Question	Response
PRA		**3.4 Simplified EDG Testing**	
PRA	16	Section 3.4 states: "There is an additional benefit that some of the tests could be simplified, which in turn could result in fewer operator distractions during plant operation." Please describe how a licensee would model the risk impact of simplified tests, including the impact of fewer operator distractions during plant operation.	This is only a qualitative statement that is made in the document. The impact of this effect is not quantified in the document. This impact is difficult to quantify and it is not recommended in the document that licensees attempt to quantify this effect. In any event, we expect this to be a small, but positive impact on risk, for example by reducing potential for plant transients. Less complex testing, such as LOOP/LOCA testing of EDGs, could lead to improvements in test-caused failure probability; however, these were not quantified. The revised LTR also does not propose quantification of these benefits.
PRA		**3.5 Increased Motor-Operated Valve Stroke Times**	
PRA	17	Please describe how a licensee would determine which motor-operated valves (MOVs) to consider for this change, and how it would estimate the risk impact of increasing the selected MOV stroke times?	Licensees would review their maintenance data and determine which MOVs have disproportionate preventive or corrective maintenance associated with preserving a stroke time that is artificially short due to the current LBLOCA-LOOP requirement. This is only a qualitative statement that is made in the document. The impact of this effect is not quantified in the document. This impact is difficult to quantify and it is not recommended in the document that licensees attempt to quantify this effect. In any event, we expect this to be a small, but positive impact on risk. The revised LTR calls for a qualitative evaluation to be performed for each proposed modifications. If this evaluation shows that the proposed modifications either have a beneficial impact on plant CDF and LERF, or have no negative impact, then those modifications will not be modeled in the PRA as part of the submittal. We believe that increasing the stroke time of the MOVs would not require a PRA quantification to be performed as part of individual plant submittals.

Source	RAI #	Question	Response
PRA		**3.6 Automatically Start One Residual Heat Removal Loop in Suppression Pool Cooling Mode**	
PRA	18	Section 3.6 discusses the risk benefit from automatically starting one residual heat removal (RHR) loop in suppression pool cooling mode. In the event of a LOCA and failure of the RHR loop that is aligned for injection, the operator would have to align the other loop (e.g., the one aligned to start in suppression pool cooling mode) to inject. RG 1.174 includes seven elements that serve as guidelines for assessing the adequacy of defense-in-depth. These include: A reasonable balance is preserved among prevention of core damage, prevention of containment failure, and consequence mitigation. Over-reliance on programmatic activities to compensate for weaknesses in plant design is avoided. System redundancy, independence, and diversity are preserved commensurate with the expected frequency, consequences of challenges to the system, and uncertainties (e.g., no risk outliers). Defenses against human errors are preserved. Please describe how adequate defense-in-depth is maintained for this proposed change. How would a licensee assess the risk associated with the resulting asymmetry in plant design and attendant impact on operator training complexity? How would a licensee assess the potential for RHR system water hammer if it was necessary to switch the suppression pool cooling loop to the injection mode during an accident?	<u>Defense-in-Depth</u> The reasonable balance between prevention of core damage, prevention of containment failure, and consequence mitigation is maintained following this change. Making this change would reduce CDF associated with sequences involving loss of containment heat removal because the main system for performing this function would be initiated automatically rather than manually. The change would increase CDF for sequences involving loss of injection, because only one division of RHR would be started automatically in LPCI mode. Further, LPCI could not be used to automatically reflood the core in those LBLOCA scenarios in which the break is in the recirculation loop that receives the LPCI flow. Because loss-of-containment heat removal sequences make up a larger fraction of the BWR risk profile than loss of injection sequences, this change would result in a net reduction in CDF. This change provides improvements to the plant design, but is not related to any perceived weakness in plant design. System redundancy, independence, and diversity are not altered by this change. Defense against human errors is improved slightly by this change, by eliminating the need for operators to manually align suppression pool cooling. <u>Plant Asymmetry</u> This will be addressed in the same way that such asymmetries and complexities are currently addressed through plant procedures and training. <u>Water Hammer</u> The potential for water hammer is very low probability when the system remains pressurized. In addition, the potential for the alignments that lead to the water hammer events would be the same under the current design and the proposed change. This is because the current plant procedures (and design) require the operators to establish suppression pool cooling as soon as adequate core cooling has been assured. Plant procedures will be written or revised as necessary to minimize the likelihood of this occurrence.

Source	RAI #	Question	Response
PRA	19	Miscellaneous Comments The TR contained a number of administrative and clerical errors, including:	See below for responses to Comments 19-1 through 19-8.
PRA	19-1	Section C.4.5, first paragraph, refers to General Design Criteria (GDC) 16 vice GDC 17.	The typographical error will be corrected in revision of TR to reflect correct GDC number (GDC 17).
PRA	19-2	Section C.4.5 states, "Figure C.4-3 shows the generic model logic for loss of offsite power events." However, Figure C.4-3 is entitled "Medium LOCA Conditional Core Damage Frequency [sic]." The correct reference appears to be Figure C.4-1, and it would appear that Figure C.4-3 should refer to "probability" vice "frequency."	The typographical error will be corrected in revision of TR to reflect correct figure number C.3-2 (LOSP event tree). "Frequency" will be changed to "Probability" on Figure C.4-3.
PRA	19-3	Section 9.1 contains 17 PRA assumptions to be validated by plants referencing the TR. There are 18 assumptions listed in Section C.6.1. It appears that numbers 5 and 14 in Section C.6.1 were combined in the Section 9.1 list. It would be clearer if these lists were consistent.	The two lists of assumptions will be made consistent in the revision to the TR.
PRA	19-4	Section 2.2, Page 6 cites References 3, 8, and 10 as the basis for the consequential LOOP probability used in the TR. Section 4.2, Page 16 cites References 2, 3, and 10.	All four references will be listed in both places in the revision to the TR.
PRA	19-5	Table C.6-1, Page C-66 discusses offsite power configurations. The "assessment" column states: "Section C.3.5 discusses this aspect of the generic model as it applies to other plant configurations." However, Section C.3.5 is "Simplified Level 2" and does not appear to address offsite power configurations.	"Section C.3.5" will be corrected to "Section C.4.5" in the revision to the TR.
PRA	19-6	Table C.6-1, Page C-67 discusses battery depletion time: "Section C.3 discusses the impact that different battery ratings have on the analysis." The NRC staff could not find this discussion in the TR.	"Section C.3" will be corrected to "Section C.4" in the revision to the TR.

Source	RAI #	Question	Response
PRA	19-7	Figure C.4-1 is very difficult to read.	A clearer image for Figure C.4-1 will be used in the revision to the TR.
PRA	19-8	Section C.4.5, "Offsite Power Configuration" states that "Figure C.4-3 shows the generic model logic for loss of offsite power events." It appears that the correct reference is Figure C.4-1.	The typographical error will be corrected in revision of TR to reflect correct figure number C.3-2 (LOSP event tree).
PRA	20	The sensitivity study in Section C.6.2.4 shows that not inhibiting the automatic depressurization system (ADS) causes an increase in CDF for the "LPCI Does Not Start With On [sic] Offsite Power" case. This same case shows a CDF decrease if ADS inhibit is credited. However, Table C.6-1, on Page C-63, states for the ADS assumption: "The results show that this assumption does not impact the conclusions of this report." Please explain these results.	There is a small decrease in CDF for this case, with the base model (ADS inhibited). There is also a small increase in CDF for this case when ADS is not inhibited. However, both of these changes to CDF are very small, especially in comparison to the assumed CDF increase of 1 x 10^{-6} from LBLOCA/LOOP. It is on this basis that the statement is made concerning the assumption not impacting the conclusions of the report.
PRA	21	Section C.6.2 presents seven sensitivity analyses. Several apparent errors and a non-intuitive presentation format render this section very difficult to understand. Please address the following if Section C.6.2 is to be retained:	See below for responses to Comments 21-1 through 21-8.
PRA	21-1	All of the tables in Section C.6.2 use "CDF Decrease" as the metric; this is difficult to interpret as discussed in specific cases below. All of the tables have a column, "LPCI Does Not Start With On Offsite Power." Please provide a more descriptive heading.	The typographical error will be corrected in the revision to the TR. Heading will read "LPCI Not Supplied by Onsite Power" or "LPCS Not Supplied by Onsite Power", as appropriate.
PRA	21-2	Tables C.6.2.2 through C.6.2 4 have the same two row labels, which are apparently meant to define the base case and sensitivity case conditions. The latter two tables should have rows related to "Service Water Injection Source" and "ADS Actuation," respectively.	The typographical error will be corrected in the revision to the TR to make the row labels more descriptive of the sensitivity cases.

Source	RAI #	Question	Response
PRA	21-3	For the sensitivities involving "LPCI Does Not Start With On Offsite Power," Tables C.6.2.2, C.6.2.3, C.6.2.5, and C.6.2.7 appear to show an improvement in risk (a larger "CDF Decrease") as a result of model changes that would be expected to increase risk.	These sensitivity analyses were done for the purpose of showing that plant to-plant differences do not affect the LTR conclusion on risk-benefit of the identified changes. With the proposed approach to do plant-specific analyses in the revised LTR, there is no longer a need for these sensitivity studies. For those cases, the raw CDF is higher and the CDF decrease is also higher. The expected increase in risk (CDF) is present for these cases, but is only an interim value used to calculate the CDF decrease shown in the referenced tables. The CDF decrease shown in the tables reflects the increased importance of removing LPCS or LPCI from onsite power given the model changes related to the sensitivity.
PRA	21-4	For sensitivities involving "Increased DG Reliability," Tables C.6.2.1, C.6.2.3, C.6.2.5, and C.6.2.7 appear to show an improvement in risk (a larger "CDF Decrease") as a result of model changes that would be expected to increase risk.	These sensitivity analyses were done for the purpose of showing that plant to-plant differences do not affect the LTR conclusion on risk-benefit of the identified changes. With the proposed approach to do plant-specific analyses in the revised LTR, there is no longer a need for these sensitivity studies. For those cases, the raw CDF is higher and the CDF decrease is also higher. The expected increase in risk (CDF) is present for these cases, but is only an interim value used to calculate the CDF decrease shown in the referenced tables. The CDF decrease shown in the tables reflects the increased importance of improved EDG reliability given the model changes related to the sensitivity.
PRA	21-5	The results for Tables C.6.2.1 and C.6.2.2 are opposite for the two model changes shown; i.e., risk goes up for one change and down for the other as a result of the same sensitivity analysis.	These sensitivity analyses were done for the purpose of showing that plant to-plant differences do not affect the LTR conclusion on risk-benefit of the identified changes. With the proposed approach to do plant-specific analyses, there is no longer a need for these sensitivity studies. The values shown in the tables reflect the relative importance of removing LPCS or LPCI from onsite power (or increasing EDG reliability) with the changes related to the sensitivity in place. (See responses to questions 21-3 and 21-4).

Source	RAI #	Question	Response
Electrical	1	Section 1, Introduction, describes the scope of the TR to the coincident large break LOCA (LBLOCA) with a loss-of-offsite power (LOOP).	See below for responses to RAIs 1a and 1b.
Electrical	1a	The TR indicates that the capability of mitigating a LBLOCA will be removed from the design requirements for the onsite power system. Confirm that the capability to respond to a LBLOCA will remain if offsite power remains available	Yes. The capability of mitigating a LBLOCA, if offsite power is available, will be retained. The retention of this capability is the key difference between this LTR and the proposed 50.46a.
Electrical	1b	With only the offsite power system remaining to power the LBLOCA mitigating systems, describe the design and acceptance criteria for an operable offsite power system. Also, describe how you propose to modify the nuclear power plant technical specifications to ensure an adequate offsite power system will be available when needed.	Because this capability is being retained within the design and licensing basis, no additional reliance on offsite power is needed. Therefore the existing design and TS requirements are adequate.
Electrical	2	Section 3.1, Allow Emergency Diesel Generator (EDG) Warm Up Prior to Loading, indicates that for small breaks, based on the time required to depressurize the reactor system, a diesel start and load time of less than 100 seconds would result in an acceptable peak cladding temperature (PCT).	See below for responses to RAIs 2a and 2b.
Electrical	2a	Confirm that for this scenario, the low-pressure pumps would automatically load onto the EDG and the high-pressure injection systems would not be required. If this is true, justify the deletion of the defense-in-depth caused by the elimination of the high-pressure response.	The high-pressure core cooling response is not being eliminated as part of this modification. However, in the analysis, high-pressure injection is assumed to have failed under single failure criteria. If the high-pressure systems are assumed functional, very little EDG loading will be required for much longer intervals. Section 3.1 indicates that the controlling factor is the time to depressurize to the low-pressure ECCS injection permissive, which is greater than 100 seconds. This means that there is sufficient time to allow the EDGs to warm up prior to loading the low-pressure pumps, given a loss of offsite power. Defense-in-depth has been maintained.

Source	RAI #	Question	Response
Electrical	2b	Provide the limiting size of the small or medium break LOCA (SBLOCA or MBLOCA) that would be acceptable if it took 100 seconds for the EDG to start and load. Also, describe the range of consequences associated with break sizes from the limiting SBLOCA up to the design basis break of the LBLOCA with a EDG start and load time of 100 seconds.	Appendix B of the LTR demonstrates that all break sizes can be mitigated using an approximately 100 second start time using best-estimate methods and severe accident success criteria. The implementing Licensees are required to maintain their design bases for the small and medium break LOCAs and continue to meet 50.46 requirements after implementing the LTR changes. Each plant will have to demonstrate this in its application. The demarcation between design basis and beyond design basis LOCAs is based on the initiation frequency of certain pipe breaks and the conditional probability of LOOP at the implementing plant. The implementing plant will decide the specific point of demarcation. As an example, based on the LOCA frequency values in NUREG-1829, certain plants may be able to justify exemption for break sizes of 7" diameter and above.
Electrical	3	Section 3.2, Optimize the Loads on to the EDGs, indicates that a new automatic load sequence would replace some of the high capacity (emergency core cooling system (ECCS)) pumps such as low pressure core spray and low pressure core injection (LPCI) with support equipment such as battery chargers, drywell coolers, and some equipment closed cooling loops. Identify those plants that do not automatically load the safety-related battery chargers onto the EDG at present. Justify why the battery-chargers are not automatically loaded as soon as possible to keep its reflected load on the EDGs low compared to its current-limited rating that would be required if the battery chargers are manually loaded after two to eight hours.	Since this LTR is no longer intended be a bounding analysis per the BWROG meeting with NRC on February 14, 2006, a response to this question is no longer required.

Source	RAI #	Question	Response
Electrical	4	Section 3.3, Start EDGs Only When Needed, proposes to eliminate the anticipatory LOCA start of the EDGs and only rely on the low voltage signals to start the EDGs.	See below for responses to RAIs 4a and 4b.
Electrical	4a	Confirm that it is the intent to only start the EDGs on undervoltage (with a fast start)	Yes, for this option, It is the intent to only start the EDGs on bus undervoltage or degraded voltage conditions, with a fast start. However, it is expected that most plants will combine this option with the change described in Section 3.1, which deals with eliminating the fast start, allowing the EDGs to warm up prior to loading.
Electrical	4b	Confirm that is your intent to not start the EDGs at all on "only" LOCA, not even using a "slow" start to bring the EDG up to speed for a controlled loading.	Yes, it is the intent to not start the EDGs when only a LOCA signal is present.
Electrical	5	Describe the response of the plant to the full range of LOCAs between "a few seconds" delayed LOOP and "a few minutes" delayed LOOP.	Our evaluation considers both the simultaneous and delayed (by up to a few minutes) LOOP events as leading to core damage. "A few minutes" is determined by the time for core reflood to occur. Any LOOP after the reflooding is not specifically modeled in the PRA and is not considered to be risk significant. Only a large break LOCA/LOOP was considered in this topical. Small and intermediate breaks, with delayed LOOP, are outside the current licensing basis of the plants. It is not the intent of this LTR to revise that licensing basis. This approach was agreed to with NRC staff in the presubmittal meetings.
Electrical	6	Describe differences and the trade offs between [fast] starting and running the EDGs unloaded, [and] a slow start and warmup scenario on: Lubrication efficiency Capability to accept load (any differences in the "Probability to Accept Load") The elimination of the delayed "Failure to Start" probability	A diesel generator expert has indicated that prelubrication and slow starts do help lubrication efficiency. We do not want to make fast starting or running the EDGs unloaded for long periods of time common practices in the industry because they can lead to EDG degradation over time. None of the scenarios listed would affect capability or probability to accept load.

Source	RAI #	Question	Response
Electrical	6a (new, from NRC clarification)	From 3.3, Start EDGs Only When Needed, Page 12 *Another safety benefit of eliminating the anticipatory EDG starts comes from an increase in diesel availability and reliability. When spurious EDG starts occur, remedial actions, such as running the EDG under load for a period of time to clear cylinder soot buildup, are typically necessary to restore the equipment to full integrity. This effect has been analyzed using the generic PRA model discussed in Section 4. Additionally, a diesel generator that has been unnecessarily started during an accident or transient and has been successfully secured may incur damage if offsite power is subsequently lost and an actual start demand occurs. One mechanism for this damage is that the hotter oil in a recently shutdown EDG does not lubricate all portions of the EDG, such as turbochargers, as well as if the oil was at normal, standby temperature.* *A third safety benefit of eliminating the anticipatory EDG starts is that there should be fewer spurious EDG actuations. A reduction of the number of signals that will cause a start will result in a reduction of the number of spurious starts. Since any reduction in demands reduces wear on the equipment, unavailability should decrease and reliability should increase as a direct consequence of this change.* Eliminating the "Anticipatory EDG start signal" Places more reliance on the operator action to "manually start" or wait for the "LOCA start signal" decreasing the reliability of the starting	While diesel generator experts agree that incremental improvements in current reliability and unavailability would be difficult to quantify, they also feel that the recommended relaxation is at least risk neutral and may afford a small improvement in these performance parameters. To address the specific questions, after the elimination of the anticipatory start signal, the diesels will continue to start on an undervoltage signal (LOOP) and not a LOCA start signal. There is no additional reliance placed on operator action to start the diesel. The anticipatory LOCA signal is viewed as a detriment in all LOCA scenarios except those with delayed LOOP, which is a small fraction of all LB LOCA/LOOPs. The BWROG PRA evaluation, which included delayed LOOP scenarios, demonstrated that risk is improved by removal of the anticipatory LOCA start, as it allows operator actions to be applied to more beneficial mitigative actions (see Section C 5.5 of the LTR) than securing an unneeded running diesel. Diesel generator experts have indicated that prelubrication and slow starts do help lubrication efficiency. We do not want to make fast starting or running the EDGs unloaded for long periods of time common practices in the industry because they can lead to EDG degradation over time. In addition, the BWROG will remove this statement (regarding lubrication efficiency) in the revised LTR. Regarding the question related to differences in loading schemes depending on the power source available, this is a plant-specific matter and will be addressed by the plant if this relaxation is sought. The appropriate surveillance testing will be reflected in each licensee's application.

Source	RAI #	Question	Response
		circuit. Also the "Anticipatory EDG starting" eliminates the delayed failure to start because the EDG is already running. The mention of lubrication efficiency in the first paragraph (hotter oil in a recently shutdown EDG does not lubricate all portions of the EDG) is unsupported by the discussion. How long does the engine have to be running unloaded to heat the lubricating oil such that its lubricating properties are in question? Why is this different than the lubrication in a hot running engine? The statement in the second paragraph (unavailability should decrease and reliability should increase) is not supported by the discussion. From 3.4, Simplified EDG Testing, page 13 *For example, to satisfy the accident response assumptions associated with a LLOCA concurrent with LOOP, RHR pumps must load onto the DG-powered board immediately (typically less than 1 second) after the DG ties to the board. The DG is therefore subjected to the application of a very large load just a few seconds after its cold, fast start. Additional loads are sequenced onto the DG in fairly quick succession. The timing relays which accomplish this loading have tight tolerances, both to assure reflood times are within those assumed in the accident analyses, and also to ensure that the DG can recover adequately before the next load is applied.* *Upon separation of the LOOP and LOCA*	

Source	RAI #	Question	Response
		events as requested by this LTR, the DG is allowed a warm-up period prior to connecting to the associated electrical board. The start times of the RHR pump and other loads are not as critical in a smaller break scenario, so the timing relays' tolerance need not be so tight, and the DG can be allowed a greater recovery time between load applications. The longer start times impose less stress upon the DG and require less timing precision in the loading sequences, while maintaining adequate margins to accident analyses assumptions. These paragraphs imply that the EDG will accept load more reliable when the load is applied slowly. This statement is not supported by the discussion. In addition the implication that there will be one loading sequence for LBLOCA when powered from the offsite power supply and a different loading sequence for MBLOCA and smaller LOCAs when powered from the onsite power supply will unnecessarily complicate the ESF load control circuit leading to more testing, not less testing.	

Source	RAI #	Question	Response
Electrical	7	Section 3.4, Simplified EDG Testing, indicated the changes would result in a relaxation of acceptance criteria. It would appear that additional testing would be required to test for different LOCA break sizes and different loading responses depending on whether offsite power was available or not. Describe what testing acceptance criteria can be relaxed.	Possible Tech Spec changes include: SR 3.8.1.7 (NUREG-1433) can be relaxed to reflect a new diesel start time SR 3.8.1.9 is modified to reflect any change in single largest post-accident load SR 3.8.1.11 can be relaxed to reflect the new diesel start time SR 3.8.1.12 is eliminated with the elimination of the LOCA-only start SR 3.8.1.15 can be relaxed to reflect the new diesel start time SR 3.8.1.17 is eliminated with the elimination of the LOCA-only start SR 3.8.1.18 can be relaxed to reflect the new optimized diesel loading sequence SR 3.8.1.19 can be relaxed to reflect the new diesel start time and new optimized loading sequence SR 3.8.1.20 can be relaxed to reflect the new diesel start time
Electrical	8	Some BWR EDGs are only capable of starting the large residual heat removal (RHR) loads at the beginning of the loading cycle where margin exists between EDG rating and load demand. Describe how this restriction will affect the proposed changes.	Plants implementing this LTR will need to insure that their loading sequence is within the capability of the EDGs.
Electrical	9	Describe what regulatory requirements are referenced in the statement "...loads that often have to be load shed under the current regulatory requirements." Clarify if this is an inference to the voltage and frequency limits that may be challenged using an undersized EDG.	No such inference is intended. Diesel loading is currently optimized for unlikely event sequences (LBLOCA/LOOP) as required by GDC 35. The LTR will allow loading sequences to be optimized for more likely event sequences.
Electrical	10	Section 3.5, Increased MOV [motor-operated valve] Stroke Times, states separating a LBLOCA from LOOP will allow slower valve stroke times. Explain why the faster stroke times will not be required if the ECCSs are powered from offsite power.	Current MOV stroke times are set short enough so that the core can be re-flooded prior to exceeding regulatory limits (PCT) for all break sizes following a loss-of-offsite power and subsequent EDG start and load. When offsite power is available, the time delay due to DG start and load times is no longer the limiting parameter for ECCS injection. After implementing the LTR, with offsite power available, longer MOV stroke times will result in ECCS injection no later than when powered from the DG. Each plant seeking this relaxation will need to demonstrate that the relaxed MOV stroke times will continue to meet the current regulatory limits.

Source	RAI #	Question	Response
Electrical	11	Section 3.5 also states that thermal-hydraulic analysis has shown that adequate PCT can be maintained for a wide range of stroke time relaxations.	See below for responses to RAIs 11a and 11b.
Electrical	11a	It is not clear how stroke times for MOVs which can be powered by both the offsite power system and the onsite power system are being addressed in this section. Is the family of valves being considered restricted to only those systems which are not required to respond to the LBLOCA? Have stroke time relaxations been discussed in a separate TR or requested under a separate plant-specific change request that may provide further clarification?	No. The family of valves being considered for stroke time relaxation includes only those required to respond to the LBLOCA (ECCS injection valves). Each plant seeking this relaxation will need to demonstrate that the relaxed MOV stroke times will continue to meet the current regulatory limits.
Electrical	11b	Section 3.5 notes that one MOV has experienced severe damage during a test under these conditions. Describe the damage and the relation to fast stroke times. Confirm that the damage was not caused by incorrectly set thermal overload relay or torque switch selection.	This reference will be removed from the LTR.
Electrical	12	Clarify the statement in Section 3.5 that larger operators can add to EDG loading constraints. Explain why the existing (short-time) EDG ratings are challenged by the higher load of the existing fast acting MOVs.	In general, larger operators impose greater loads on the EDGs. However, this statement should not be construed to mean that existing loads challenge the EDG ratings beyond design requirements.
Electrical	13	In general, pump suction valves affect pump net positive suction pressure and pump discharge valves affect pump horsepower. Address the differences between the suction and discharge valves for the ECCS pumps.	See below for responses to RAIs 13a and 13b.
Electrical	13a	Confirm that the slower stroke times will not affect the starting or restarting loads seen by the EDG.	Slower stroke times for the discharge valves reduce the rate of pump electrical loading seen by the EDGs.

Source	RAI #	Question	Response
Electrical	13b	Confirm the ECCS pumps will not have a problem with inadequate suction pressure.	ECCS suction valves are maintained in the open state for standby readiness. No ECCS suction valves have to change state during the early stages of the event. Stroke times for these valves are not changed by this LTR.
Electrical	14	Clarify the statement in Section 3.6, Automatically Start One RHR Loop in Suppression Pool Cooling Mode (SPC), that in order to make this change, a licensee would have to deterministically demonstrate that it could still mitigate the LBLOCA with offsite power available and a single active failure. The NRC staff believes this section can only apply to those plants that have two RHR pumps per division where it would be proposed to permanently re-align one of the two RHR pumps per division to the SPC mode. Otherwise, clarify why this has not already been demonstrated under the existing requirements.	A licensee should deterministically demonstrate that it could still mitigate the LBLOCA with offsite power available and a single active failure to confirm that compliance with the design basis is not degraded through implementing this relaxation. The permanent realignment described by the NRC is not required in order to implement this option. The NRC's perception that "this section can only apply to those plants that have two RHR pumps per division where it would be proposed to permanently re-align one of the two RHR pumps per division to the SPC mode" is not correct. It is impractical to align RHR systems in BWRs in the manner described. Current regulatory requirements to consider a simultaneous LOOP and single failure preclude implementation of this option.
Electrical	15	Clarify the last paragraph of Section 3.6 to explain why the core damage frequency (CDF) due to loss of containment heat removal is higher than damaging the core (i.e. melting the core) from failure to reflooding the core because of loss of injection.	This statement is simply a general statement summarizing the PRA results for BWRs. The core damage frequency contribution from loss of containment heat removal sequences is higher than the contribution from loss of injection sequences. In any case, per the revised LTR, each licensee will calculate its own change in CDF and LERF (decrease or increase) due to starting one RHR Loop in Suppression Pool Cooling mode, using its own plant-specific PRA model.
Electrical	16	Section 3.7, Eliminate LPCI LOOP Select, states that "In the current LOCA analyses for Loop-Select plants, the logic is assumed to fail (i.e. select the broken loop) for all breaks less than or equal to 0.5 ft^2. This is well into the large break range, so elimination of this function will not affect other postulated accidents." Describe why other postulated events LESS than 0.5 ft^2 will not be a concern.	Loop select logic is used only to mitigate Large Break LOCAs, and for no other accidents or transients. As 0.5 ft^2 is considered to be a Large Break LOCA, <u>all</u> Small and Intermediate Break LOCAs are less than 0.5 ft^2. Thus, the currently assumed failure of the Loop Select logic in the deterministic T/H analysis for all breaks less than 0.5 ft^2 has no impact on SBLOCA or IBLOCA mitigation. Thus, removing the Loop Select logic will have, at worst, no impact but could have a positive impact on the T/H analysis of SBLOCA/IBLOCA depending on single failure assumptions.

Source	RAI #	Question	Response
Electrical	17	Section 4.3.1, Quantitative Impact of Optimizing EDG Loads, appears to attempt to provide a risk trade-off of manually loading two to four (or more) battery chargers before the batteries discharge to the point of inadequate direct current voltage against the elimination of core injection on a LBLOCA. Clarify why the consequences of a discharged battery are comparable to damaging the core and a deliberate loss of the primary fission barrier.	The trade-off does not involve loading battery chargers onto the EDGs at the expense of eliminating low-pressure injection. The trade-off is that excess low pressure ECCS capacity (either all LPCS pumps or 2 of 4 LPCI pumps) is no longer automatically loaded onto the EDGs, which would allow more beneficial loads, from a core damage risk perspective, (such as battery chargers) to be automatically loaded. The complicated tasks of AC and DC load shedding would be greatly reduced or eliminated. The generic BWR4 PRA model showed a risk decrease resulting from making this change. In any case, per the revised LTR, each licensee will evaluate this change using its own plant-specific PRA model to calculate the change in CDF and LERF resulting from this change.
Electrical	18	Section 4.3.4, Qualitative Risk Reductions, addresses three areas in the first paragraph: EDG Availability, EDG Reliability and Operator Action Reliability. The implication is that spurious starts reduce EDG availability and reliability. Describe how many false starts can be attributed solely to a false LOCA signal and what percentage of unavailability and unreliability can be attributed to that function.	A review of 37 LERs listed in NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," Table A-2 for unplanned EDG demands during critical operation that were not identified as a loss of offsite power, from 1999 through 2003 (1998 LERs not readily available) yielded no events related to ECCS LOCA signals. The recommendation in the LTR is to remove the logic that starts the EDGs on a LOCA alone and only start them when there is an actual undervoltage or LOOP. Any fast start is believed to have a detrimental effect on EDG reliability, as described in NRC Generic Letter 84-15 and NRC Information Notice 85-32. This would eliminate unnecessary fast starts of the EDGs due to both spurious LOCA signals and actual LOCAs, if offsite power remained available. Even though it is believed that these events are fairly rare, eliminating these fast starts will have a positive effect on EDG reliability, however small that improvement might be.
Electrical	19	If the existing LOCA logic is a significant contributor to spurious EDG starting and has a negative effect on EDG availability and EDG reliability, clarify why the existing deficient logic has not been corrected under the Maintenance Rule and describe your recommendation to revise the logic.	The current logic is optimized to respond to only LB LOCA/LOOP scenarios, which is required by the current licensing basis. The purpose of this LTR is to provide justification for an exemption from this licensing basis requirement so that this beneficial change can be implemented. As stated in the response to Question 18 above, it is acknowledged that spurious EDG starts from this logic are now rare; hence it would not be addressed under the Maintenance Rule. The recommendation to remove the LOCA logic to start the EDGs is aimed at reducing the number of fast starts and thus incrementally improving EDG reliability and unavailability. Just as important, it also removes the operator burden from having to respond to these unnecessary starts.

Source	RAI #	Question	Response
Electrical	20	It appears that an arbitrarily assumed improvement of 10 percent in operator action reliability was used to justify the offset in the increase in CDF from the proposed changes. Clarify how an operator action hours into the accident, can offset the immediately assumed damage to the core from failure to recover.	The offsets are reductions in overall risk (CDF and LERF) due to reductions in the frequency of other PRA sequences, not LBLOCA/LOOP, resulting from benefits associated with making one or more of the changes described. These reductions are used to balance the increase in risk resulting from assuming that a LBLOCA/LOOP goes directly to core damage. Any improvement in operator reliability (not necessarily 10%) can be used to show that the overall changes in risk are beneficial. The response to PRA RAI 14 addresses the licensee action for implementing the changes in the HRA, if needed.
Electrical	21	Appendix A, General Design Criterion (GDC) 35, Emergency Core Cooling, to Title 10 to the Code of Federal Regulations Part 50 is only one of six GDCs that require onsite power. The others are GDC 33, Reactor Coolant Makeup, GDC 34, Residual Heat Removal, GDC 38, Containment Heat Removal, GDC 41, Containment Atmosphere Cleanup and GDC 44, Cooling Water which also require onsite power. Address the effect that a slow start and delayed loading of the EDGs would also have on the response of these systems and address the total effect on CDF.	Section 6.2.3 of this LTR addresses the impact on each of these GDCs. The cited GDCs do not impose as stringent design requirements as does GDC 35 on the affected equipment. The functions associated with the cited GDCs are not time-critical in the accident analysis such that the proposed relaxations in diesel start time (less than 2 minutes) would have a negative impact on their mission time. Therefore, we do not anticipate compliance issues with these GDCs as a result of the changes in the LTR. Each plant will confirm the impact of its proposed changes on its licensing basis with respect to the GDCs, since each plant's commitment to the GDCs is different.

Source	RAI #	Question	Response
T/H	1	A recent paper comparing calculations performed for a pressurized water reactor using MAAP and RELAP5, Park, C.H., Lee, D. Y., Lee, I. J. U. C., Suh, K, and Park, G. C., "Comparative Study of Loss-of-Coolant Accident Using MAAP4.03 and RELAP5/ MOD3.2.2," ICONE10-22439, Proceedings of ICONE10, Arlington, VA, April 14-18, 2002, noted that the same initiating event resulted in significantly different predicted sequences of events for a large break LOCA. One point in particular mentioned is that the break flows and emergency core cooling system (ECCS) flows were significantly different. Explain what is done to get "Approximately the same total break flow...," stated in Section B.4.2.1.	The fundamental parameters of MAAP were not altered from the default values in order to achieve approximately the same break flow. The BWROG used the same break location and flow areas that are modeled in the standard SAFER/GESTR large break LOCA analyses for BWRs. As discussed in the meeting between the BWROG and NRC on February 14, 2006, and subsequent phone calls, it was not intended for the BWROG to review and comment on the cited papers. It is our understanding that they are cited only as background material.
T/H	2	Large break LOCA analysis necessitates proper accounting for conservation of momentum. Provide the development of the conservation of momentum equation as applied in MAAP with detailed discussion of each of the following components: (1) temporal change of momentum, (2) momentum convection, (3) area change momentum flux, (4) momentum change due to compressibility, (5) pressure loss resulting from wall friction, (6) pressure loss resulting from area change, and (7) gravitational acceleration.	Follow-on discussions with NRC indicated that a formal response to this RAI was not required. It is well established that MAAP utilizes simplified break flow models and does not include all of the effects described in the RAI. The critical flow models in MAAP have been compared against several separate effects tests as described in the response to RAI 3 and show relatively good agreement. It is important to note that the simplified modeling tends to show wider variation with the test results only during the very early time periods of a LOCA and that longer term (greater than a minute) behavior tends to compare more favorably.

Source	RAI #	Question	Response
T/H	3	Provide code versus experimental data assessment cases for MAAP, including break flow, system depressurization, core flow, collapsed two-phase level, and ECCS injection. Assessment cases must include separate effects tests, component tests, integral systems tests, and plant data where available. The comparisons must also indicate the ranges of applicability of the experimental data for the large break LOCA in a BWR.	EPRI has previously provided the NRC with the following documents: EPRI TR-100741, "MAAP Thermal-Hydraulic Qualification Studies" EPRI TR-100742, "MAAP BWR Application Guidelines" EPRI TR-100743, "MAAP PWR Application Guidelines for Westinghouse and Combustion Engineering Plants" The documents qualify the thermal-hydraulic models in MAAP for predicting system response during the early phases of a severe accident and assess the code's ability to model these phenomena. Comparisons to other codes, separate effects tests, integral tests and plant data are made with MAAP to identify any limitations using the code. Included in the referenced documents are MAAP comparisons to GE Small and Large Vessel tests, EPRI Valve Testing Program, Semiscale, FIST, RELAP, RETRAN and the GE SAFER code.
T/H	4	Describe the MAAP CCFL model and provide assessment results.	The MAAP model represents a channel quench front descending into the core. The basic assumption is that the rate at which the core spray can enter the core is governed by a counter-current flooding limitation. That is, the maximum rate at which water collecting above the core can enter is that rate at which water would just be flooded by the escaping steam. This rate is evaluated using the Kutateladze [1] equation as presented Fauske [2]. References: [1] S.S. Kutateladze, "Elements of the Hydrodynamics of Gas-Liquid Systems," Fluid mechanics – Soviet Res., Ed. 1, Vol. 4, p. 29, 1972 [2] H.K. Fauske, "Boiling Flow Regime Maps in LMFBR HCDA Analysis," Transactions of ANS, Vol. 22, pp. 385-386, 1975.

Source	RAI #	Question	Response
T/H	5	The PCT responses provided in Figures B.4-5 and B.4-10 are clearly not the same event. Provide detailed thermal hydraulic comparisons. Include flow direction and mass flow rate, two-phase level, heat transfer regime and coefficient.	The BWROG is not using MAAP as a surrogate for an Appendix K code for demonstrating compliance with 50.46. MAAP was used to determine the limiting case, then, TRACG was used to model the limiting case in detail to demonstrate mitigation capability. This was discussed with and acknowledged by the NRC reviewer subsequent to these RAIs. The two figures are the same event modeled in two different codes (MAAP and TRACG). The important results are the rate of heatup while the core is voided and the PCT and the time at which low pressure begins to inject. These comparisons also indicate that low pressure injection occurs at approximately the same times in the two codes as shown in Figures B.4-5 and B.4-10. The PCT predicted by MAAP is always higher than that predicted by TRACG, a conservative result.
T/H	6	The TR indicates that for the BWR/4 a TRACG02 PCT adder of 193 °F is applied to a PCT of 1758 °F, while the BWR/6 the PCT adder of 212 °F is applied to 1422 °F. Justify these adders and provide for the uncertainty analysis.	During the preparation of the LTR, GE's TRACG04 model was under development. TRACG04 was being developed as a LOCA model. However, it could not yet be used for regulatory analysis. It was known that TRACG02, which was approved for regulatory analysis, had limitations in modeling LOCAs. GE required the application of the adders cited in the LTR to TRACG02 results as necessary to simulate PCTs comparable to those that would have been calculated by TRACG04.
T/H	7	In a study performed by the Josef Stefan Institute, Reactor Engineering Division, "Differences Between MAAP and RELAP5 Analyses of Large Break Loss of Coolant Accident," Technical Committee Meeting IAEA, Vienna, Austria, November 15-18, 1993, it was found that MAAP over predicted the reactor vessel liquid inventory when compared with RELAP5 by as much as a factor of nine. Please provide MAAP and TRACG comparisons of reactor vessel liquid level and inventory for the BWR/4 and BWR/6 cases in the TR.	As discussed in the meeting between the BWROG and NRC on February 14, 2006, and subsequent phone calls, it was not intended for the BWROG to review and comment on the cited papers. It is our understanding that they are cited only as background material.

Enclosure 2

Outline of Revised LTR

Title: SEPARATION OF LOSS OF OFFSITE POWER FROM LARGE BREAK LOCA

Legal Notice

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Step 17: Verify and Document Compliance with Current Regulations

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5.1.3. Eliminate LPCI Loop Select

5.1.4. Allow EDG Warm Up Prior to Loading

Enclosure 3

RESPONSES TO NRC COMMENTS ON EPRI TECHNICAL REPORTS 1009110, REVISION 1 AND 1007966 REGARDING THE ISSUE OF DOUBLE SEQUENCING NUCLEAR PLANT SAFETY LOADS

Introduction

In a letter dated September 24, 2004, the NRC Staff provided comments on the BWR Owners' Group (BWROG) submittal of April 6, 2004 relating to the Electric Power Research Institute (EPRI) Technical Reports 1009110, Revision 1 and 1007966 on the double sequencing issue. The BWROG appreciates the very thorough review effort completed by the NRC staff, and provides our planned resolution to those comments in the enclosure. The attached responses were developed by EPRI and reviewed by the BWROG.

These EPRI reports are the culmination of a project to establish a common and more comprehensive understanding of the double sequencing issue. Previously documented information on double sequencing is fragmented among many industry documents spanning a decade. The EPRI reports are intended to be 'living documents' that could be improved with additional experience and understanding of the double sequencing issue. To that end, and in recognition that many of the NRC staff's comments can add substantially to the quality and completeness of the documents, EPRI intends to revise the two technical reports. The planned treatment of some comments is described in detail in this enclosure; in other cases our response simply acknowledges the need to expand the report discussions in areas affected by the comments.

The BWROG would like to highlight two specific comments. First, it is noted that Comment 4 pertains only to PWRs. The BWROG is providing a response to that comment since the EPRI generic document (EPRI 1009110) applies to both BWRs and PWRs. We have attempted to answer all questions without regard for reactor type and have provided some information that is clearly limited to BWRs. Second, NRC Comment 21 relates to the means by which PRA models can be adjusted to determine a rough estimate of the impact of double sequencing on core damage frequency. The comment touches upon the key double sequencing issue by indicating "If the vulnerabilities do not make the particular safety equipment *unavailable altogether* [emphasis added], the analysis should consider how the equipment failure rates would increase under the double sequencing scenario conditions and stresses." Redundant divisions being "unavailable altogether" for a common mode condition like double sequencing would represent an unacceptable consequence. This is the key consideration when evaluating the double sequencing issue. We believe that minor additional degradation related to equipment exposure to infrequent (and perhaps one-time) conditions cannot be quantified and might very well be undetectable as to its impact on equipment reliability. Thus, minor accelerated aging degradation to equipment for a potential one-time event is not the substantive double sequencing issue.

EPRI Technical Report 1009110

1. Page 7-2, Item 8

With regard to the grid operator's plans and expectations for system performance following the trip of a nuclear unit, it is useful to understand that: the minimum switchyard voltage required by a nuclear plant

that has no voltage regulating capability (such as auto tap changing transformers or static VAR compensators) is generally more limiting than the minimum voltage required to prevent a grid voltage collapse. The transmission system operator, therefore, cannot be relied upon to control a plant's post-trip switchyard voltage to the level that is necessary for the nuclear plant, unless the transmission operator has been made aware of the nuclear plant's requirements, and arrangements have been negotiated to control the switchyard voltage to that level, post-trip.

Response:

We concur with this comment. Note that Item 8 is one of ten considerations that bear on the estimation of a value for the probability-of-occurrence of a double sequencing event.

The NRC reviewers are correct in noting that, without prior negotiated agreements as to the pre-event voltage targets or schedule, those units without the post-trip ability to control plant bus voltage are more likely to experience a double sequencing event given identical configurations in all other respects. Note the last paragraph of Section 2.4 entitled *Causes of Double Sequencing*, wherein we state that the "initiators are more likely to occur if the grid and nuclear unit organizations are not closely coordinated both contractually and in their operations and communications protocol." Additionally, a firm agreement as to pre-trip voltage targets goes a long way to ensuring that nuclear unit (and grid) voltage will be adequate in the post-trip period without actions on the part of the grid operator.

The closing sentence of Item 8 states "Adherence to these guidelines minimizes the likelihood of double sequencing." The guidelines are those of Generic Letter 79-36, which cannot be reasonably satisfied without installed voltage regulation equipment, large voltage margins in the plant's design or close coordination with the transmission system operators. There is a Branch Technical Position (BTP) that includes similar guidelines for the more modern nuclear units to which the BTPs applied.

Based on the above, we propose to make no change to the document as a result of this comment. It is our intent that the users of the document consider all items listed in this section in arriving at their own estimation of the probability of occurrence of a double sequencing event at their nuclear unit(s). Clearly, a "loose" interface with the grid operators will, for nuclear units without the benefit of automatic voltage regulating capability, contribute to a higher likelihood of occurrence of a double sequencing event.

2. *Page 7-3 – Sentence immediately following Item 10*

"Best estimate LOOP [loss of offsite power] frequency" is not the important parameter for LOCAs [loss-of-coolant-accidents]. The important parameter for LOCAs is "conditional LOOP probability given a LOCA." This is the parameter that should be determined for LOCA initiators including degraded voltage situations.

Response:

We concur that the use of the term "best estimate" is inappropriate and plan to change the affected sentence to read "The above guidelines should assist the user in determining the probability of occurrence of a degraded voltage-induced LOOP."

It is our intention to more definitively identify double sequencing as an event that can only occur subsequent to a safeguards system actuation whether that actuation is real or spurious. In this regard, the probability of occurrence of a double sequencing event will always be preconditioned by a safeguards actuation. Thus, the term "double sequencing" has no meaning as a potentially limiting condition except when coupled with a safeguards actuation. While a spurious actuation followed by a double sequencing

condition will not be the most limiting event since it will be far more time-forgiving relative to operator response, it will expose safeguards equipment to the operational anomalies that accompany the double sequence condition.

We will revise section 7-1 wherein the term "best estimate" is used in a few instances to eliminate the word "best".

3. Page 7-3 – Partial paragraph immediately following above sentence

With regard to the statement, "While a LOOP is not likely to cause a LOCA," it is noted that a LOOP that results in a full-load rejection of a nuclear plant's turbine generator has some potential to cause a LOCA due to stuck-open safety or relief valves.

Response:

We concur with this comment and will revise the sentence to read, "While a LOOP is not likely to cause a LOCA having greater significance than a post-trip stuck open safety or relief valve, a LOCA may under some circumstances result in a LOOP."

TMI lessons learned and changes incorporated thereafter have vastly improved the operators' ability to detect and effectively mitigate the impact of a stuck valve scenario. However, this clarification of our statement helps to ensure that the evaluation of the impact of double sequencing on "stuck open valve" isolation equipment (mainly MOVs) is not overlooked.

4. Page 7-3 – Last bullet on page

With regard to the sentence that reads, "The delay in tripping the turbine is nominally about 30 seconds, however the reverse power relays usually operate considerably sooner and trip the generator." The beginning of that sentence should read, "The delay in tripping the generator is ..." Also, it is our understanding that Westinghouse plants and some other pressurized water reactors (PWRs) utilize 30 second time delays only and do not necessarily utilize reverse power relays to trip the generator and transfer loads (reactor coolant pump shaft seizure event credit).

Response:

This comment, in part, corrects our reference to the "turbine" when it should have stated the "generator". We will make this correction.

Regarding the 30 seconds time delay in tripping of the generator when mechanical and/or electrical faults are not present in the turbine generator lineup, we note that there may not be a consistent position across the PWR spectrum on this issue. A 30 second delay in tripping will cause the main generator with attached turbine to motor for several seconds. This is an undesirable condition that, at the very least, is to be minimized in terms of its frequency of occurrence. In the case of some units, protective relays, usually of the reverse power type, operate in parallel with the 30-second timer. Depending on the time setting selected for these relays, they may or may not operate faster than the 30-second timer, which, in some cases, may be caused to start timing by the detection of a reverse power condition by a separate relay.

Our discussions with Westinghouse experts revealed that their reasons for avoiding an immediate trip of the generator when conditions permit relates to the departure from nucleate boiling (DNB) advantage of maintaining forced (versus coastdown) flow from the reactor coolant pumps for at least a few seconds for

a reactor trip following a Steam Generator Tube Rupture (SGTR) event.

Documentation was provided by Westinghouse indicating a minimum requirement for 2 seconds retention of forced reactor coolant flow in the case of the KORI units (3 and 4) following a SGTR event-induced unit trip. This event is most limiting as it relates to the need for a short period of forced coolant flow following the reactor and turbine trip.

We agree that the reverse power trip of the main generator has been stated with too high a degree of certainty in our report since there are variations on this trip scheme across the industry. We will likely revise the affected sentence to read "The delay in tripping the turbine is nominally set at 30 seconds; however, there are a variation of design arrangements across the PWR spectrum. For this reason, we will amend the document such that licensees choosing to use the guidance contained herein receive a clear message that they need to understand their specific unit designs.

We note that the last sentence in the section commented on already stresses the usefulness of understanding the extent of trip delay and we remain convinced that having that knowledge will help to more fully understand the manner in which the double sequencing event would evolve. This generator trip timing discussion is of more significance to those units that normally power their safeguards buses from the unit auxiliary transformer and have either an installed generator breaker or utilize a high-speed transfer actuation to switch to their preferred offsite power source. At issue here is the likely timing of occurrence of a degraded voltage condition that leads to a double sequencing event, since it is highly unlikely that a degraded voltage condition will occur and persist when loads are powered from the main generator-connected unit auxiliary transformer.

5. *Page 7-4 – Second bullet on page*

With regard to the sentence that reads, "High-speed transfer schemes have historically functioned very reliably," NRC report AEOD/E-93-02 and EPRI Advanced Light Water Reactor [ALWR] Requirements Document for the ALWR Evolutionary Plant, Chapter 11, indicate that high speed transfer schemes have not functioned very reliably.

Response:

We concur that from some aspects and on a statistical level, high-speed transfer schemes can be shown to "have not functioned very reliably." However, for events at domestic nuclear units resulting in either a full or partial loss of offsite power, high-speed transfer schemes have not been a large contributor to these losses. EPRI Technical Report 1002987, entitled *Losses of Off-Site Power at U.S. Nuclear Power Plants Through 2001* was reviewed to arrive at this conclusion. EPRI's document lists some 149 full or partial loss of power events occurring between the years 1990 and 2001. Of these, five events can be shown to have at their root, a failure of a high-speed transfer scheme. Some of these are due to now corrected design or system operating errors. Another four events can be remotely tied to high-speed transfer scheme operation. These events generally resulted in proper scheme operation to prevent a transfer to offsite power for reasons quite apart from failures within the transfer schemes.

Conservatively counting all nine events as high-speed transfer failure-initiated events, one arrives at a 6% contribution to all loss of offsite power events (during the period studied) being caused by high-speed transfer schemes. This is not to be confused with a 6% failure rate for high-speed transfer schemes since the many times that they operate correctly are not reported in a manner that can be readily retrieved. We recognize that not all nuclear units use a high-speed transfer of safeguards buses since several are normally powered from their startup auxiliary transformers while others utilize a generator breaker that

allows the unit auxiliary transformers to remain energized even if the main generator is not operating. For this reason, the contribution of high-speed transfer schemes to LOOP events is only roughly estimated here.

We note that significant improvements have been made in maintenance practices driven by both internal industry initiatives and NRC actions (like the Maintenance Rule). These improvements serve to render historical high speed transfer failure data useful in only a very conservative sense. Additionally, and as noted above, some failures served to reveal defective transfer actuation scheme designs which were then fixed and most likely made known to the entire industry to investigate via the now available Operating Experience-related processes.

The important point being made in the report is that high-speed transfers, when they occur, do so sufficiently fast as to cause no undue stress on the equipment being transferred. Therefore, to the double sequencing issue, high-speed transfer reliability is a rather moot point, as it does not represent a worst case. A failure of the transfer would, in the case of most domestic nuclear units, result in safeguards loads being powered by the onsite emergency generators.

Since our statement can be misinterpreted in a non-conservative manner, we propose to change the wording in the report from "High-speed transfer schemes have historically functioned very reliably." To "High-speed transfer schemes have not historically been a major contributor to loss of offsite power events nor have they been demonstrated to unduly stress transferred loads."

6. Page 7-5 – First three bullets on page.

The assumptions of these three bullets is that as long as the duration of safety system deenergization is small compared to the capabilities of the batteries (1-hour useful discharge life), double, triple, or even quadruple sequencing would not affect the batteries capability. The margin that is believed to exist on the batteries is not as large as assumed here. The first one-minute loading on batteries that is due to load sequencing is almost always limiting. The battery voltages during this period are pulled down very close to the minimum required voltages of the loads due to current inrushes of loads like circuit breaker charging motors. Although the battery may have one or more hours capacity at much lower current demands, a substantial amount of capacity does not have to be discharged before it cannot meet the limiting load sequencing requirement. The battery may not be capable of providing two, three, or four load sequencing repetitions if the charger is not available due to low input voltage or late sequencing on the emergency diesel generator (EDG).

Response:

The one-minute load peak period of a nuclear unit's battery loading profile is a conservative modeling technique used to envelope the numerous very short demands on the batteries during the first moments of a worst case battery loading event. These demands, like multiple and only slightly time separated breaker operations (and subsequent operating spring recharging operations) are spread out over a time period assumed to not exceed one minute in duration. We concur that a station battery's size is oftentimes dictated by the voltage drop experienced during this short duration of peak loading, but also realize that it is the reapplication of this one minute load at the tail end of the Station Blackout (SBO) coping period (when the battery is significantly discharged) that is often most limiting. A double sequencing event without a SBO event (by definition, there will not be a SBO event) will not remove meaningful capacity from a battery even when assuming that the battery charger makes no contribution to the supply of DC System demand. We estimate that a second one-minute peak in the early seconds or minutes of an event will not be voltage limiting either, as insignificant battery capacity has been expended at that point and far fewer breakers will require tripping. We refer to those breakers that, upon a LOOP event, serve to

remove from safeguards buses all non-essential post-LOCA loading.

However, we concur that the document should not serve to relieve the users of the requirement to determine that the above is or is not the case for their unit(s), and will revise our notes, accordingly. The words "triple or even quadruple" will be removed since they have no relevance to the double sequencing issue and serve to project a sense of overconfidence relative to the ability to generically address this DC System issue. Also, while most but not all nuclear units have a 125 VDC system, some units employ a different voltage level. We will acknowledge this detail in our revised discussion.

We note that for BWRs, the more significant DC bus loading in terms of impact on the battery is that of the DC MOVs used in the design.

Your Comment 6 is closely tied to Comments 9 and 14. Accordingly, our responses to these comments refer to this response.

7. Page 7-6 – Table 7-1, Item 1 and its associated Note 1

This item evaluates 4kv motor and control switchgear buses and breakers from a loading duty cycle perspective, but that is not the limiting case for double sequencing. An evaluation should be performed of the circuit breaker (CB) anti-pump logic and load sequencing logic for the double sequencing scenario. Actuation of CB anti-pump logic due to double sequencing can result in a trip and lockout of CBs feeding safety equipment. CB anti-pump logic designs that recharge CB closing springs following a trip of the CB are especially vulnerable, but all CB anti-pump designs are vulnerable to some degree. Such vulnerability was identified at Indian Point 3 in April 5, 1994, letter to the NRC. NUREG/CR-6538 provides additional background on CB anti-pump logic vulnerabilities during double sequencing.

Load sequencing logic that is not specifically designed for double sequencing can result in overloading emergency diesel generators (EDGs) due to failure to load shed previously sequenced loads during double sequencing, paralleling the EDG out-of-phase with motor residual voltages, and/or it can simply result in lockup of the sequencer. Additional information on these load sequencing vulnerabilities can be found in NRC Information Notice 92-53, "Potential Failure of Emergency Diesel Generators Due to Excessive Rate of Loading," and NUREG/CR-6538.

Response:

We concur with the breaker anti-pumping comment and will revise the document to ensure that the user is aware of the need to complete a unit-specific review of that circuit's design and ability to function properly during a double sequencing evolution.

Regarding the load sequencing logic comment, a properly designed load sequencer must have the ability to function correctly in the long-term post-LOCA during which period a LOOP has always been deemed credible. A design that allows an emergency diesel generator (EDG) to become overloaded and/or damage itself and/or its loads due to an out-of-synchronization breaker closure is inappropriate and requires correction. A sequencer design that works properly in the long-term post-LOCA should work equally properly in the near-term post-LOCA. Nevertheless, our revisions will include references to NUREG-6538 and the related NRC Issue 171 since these can be helpful to users of the double sequencing documents.

8. Page 7-6 – Table 7-1, Item 2 and its associated Note 2

This item evaluates 4kV protective relaying. It only evaluates electro-mechanical induction disk time-overcurrent relaying. IEEE Standard 741-1997 identifies solid state overload (SSO) relays with thermal memory capability that have been used on the motors of motor-operated valves (MOVs). If these relays are also used on 4 kV motors, it provides a greater potential that the relay will trip during double sequencing because the relay is not completely reset back to zero following the first start of the motor. This is the case for any motor-current overload protective device that utilizes a thermal memory capability, e.g., thermal overload (TOL) protective devices in motor starters.

Response:

We concur that our Note 2 explanation using induction disk type time-overcurrent relays as the example too narrowly focuses on one relay type and does so without consideration for load inertia. The document will be revised accordingly, likely recommending that licensees review limiting cases. Motor overload protection is intended to mimic as closely as reasonably practical, the motor being protected and to do so with a degree of non-conservative motor protective margin (i.e., the motor needs to be in a sustained overloaded or locked rotor condition to cause the protection to operate). Thus, both load inertia and the thermal overload protection memory feature require consideration. We note that overload protective device thermal memory is one element involved in more closely mimicking motor performance in that a motor is similarly unable to immediately cool down following its deenergization.

Also related to the above as well as your Comments 18 and 20, and a topic that we need to address in a future document revision, is the manner in which short duty cycle rated motors like those used to power ac-powered MOVs are protected. The thermal overload selection process for these results in the specification of a device that cannot support continuous operation of the short duty cycle rated motors, since the motors would not be protected against too long a run if that were not the case. Thus, a motor requiring 10 amperes of running current might have a thermal overload device rated at 7 amperes. Note that the ampere values used represent a roughly estimated example case presented only to make our point here.

9. Page 7-6 – Table 7-1, Item 3 and its associated Note 3

This item evaluates 4kV 125Vdc control power. Note 3 concludes that control power for the metal-clad 4kV switchgear at most, if not all units, is supplied by a 125Vdc battery system and is therefore not subject to the effects of double sequencing. Comments 6 and 7 above apply.

Response:

Our responses to Comments 6 and 7 above relative to the 125 VDC systems also apply to this comment.

10. Page 7-6 – Table 7-1, Item 4 and associated Note 4,

a) This item evaluates 4kV pump induction motors, however, Note 4 states that the discussion is also applicable to motors of other sizes and voltage rating since the 4kV large motor case is bounding and thus applicable to Items 5, 11, 12 and 16 in the listing of evaluated components. The 4kV pump induction motor case does not necessarily bound Items 5, 12, and 16; this is actually implied in Table 7-1 itself. The table lists the "Level of Impact" for Item 4 (the 4kV pump motor case) as "None," whereas Items 5, 12, and 16 are listed as "Negligible." The

reason for the difference in Items 5 and 12 is likely due to the fact they are fan motors, rather than a pump motor like Item 4. Fans have a much higher moment of inertia than the typical pump; and, as a result, they take much longer to come up to full speed.

This means there is more motor heat-up during the start and potentially less margin between motor torque capability and the fan load torque requirement. This concept is described in the Note 4 discussion of PWR reactor coolant pump high inertia flywheel loads that are not subject to double sequencing, but is not discussed for the high inertia safety-related fan motors that <u>are</u> subject to double sequencing. Neither Tables 7-3 nor 7-4 under Note 4 provide any data on fan motors. This information should be provided as well as an evaluation of the effects of double sequencing on the fan motors. It is noted that Recommendation 1 in Chapters 9 and Key Recommendation 2 in Chapter 1 both recommend that fans be more thoroughly reviewed by plant engineering motor specialists. Fans and their motors, however, should be specifically evaluated in this EPRI report, rather than leaving it to the individual plants, since they may be the most limiting electrical motors under double sequencing conditions.

Response:

Regarding motor/load inertia and the impact of double starts on motor integrity, we concur that our document needs to evaluate a few fan-loaded motors at a minimum. Our recommendation that users evaluate bounding fan load cases will likely remain, however, as it may not be possible for the BWROG to identify a bounding typical case. It is appropriate to provide a sampling of results, however, and we will strive to obtain the necessary detailed information from the owners of the pilot units studied or from a BWR plant if a more limiting case is identified there.

b) *Note 4 discusses Section MG1-20.43 of NEMA MG1 Standard, entitled "Number of Starts." It states that properly specified and designed motors for nuclear power plants satisfy the specified conditions for applied voltage. What the Note misses and does not discus is the good likelihood that the double sequencing of the motors will be due to actuation of the degraded voltage relays due to inadequate switchyard voltages as a result of the loss of the plant's generator MVAR support to the grid. Under these conditions, the applied voltage is <u>not</u> adequate. The first start of the motors will be a prolonged start under degraded voltage conditions with substantial preheating of the motor during the start. The second start of the motors on the EDGs could also be considered somewhat of a degraded start under the NRC Regulatory Guide (RG) 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," specified minimum voltage of 75 percent and frequency of 95 percent. Section MG1-20.45 of the NEMA MG1 standard specifies an applied voltage of plus or minus 10 percent of rated voltage, with rated frequency. Under the degraded voltage condition discussed, the applied voltage will not meet the minimum specified voltage in MG1-20.45; and as a result will not meet the requirements in MG1-20.43 for two starts in succession. This should be discussed in Note 4. It is noted that in Section 2.3, page 2-3 of the report, there appears to be no acknowledgement that switchyard voltage could drop immediately following the trip of the plant's generator due to the loss of the generator's MVAR support to the grid. This should be addressed in Section 2.3.*

Response:

Regarding the potential that the first start of critical motors will be attempted with a degraded voltage (less than 90% of motor rating) applied, we will add discussion advising users to evaluate a bounding

case using the minimum voltage which could persist for the duration of their second level undervoltage relay time delay. We note that safety related motors for the pilot units were specified for purchase with an ability to start loads with a minimum of 80% (and in some cases, 70%) of rated voltage applied. Our document revisions will provide advice to licensees to consider any better than standards-specified capability that they may have built into the nuclear units.

Judgment should be exercised in this area, realizing that hypothetically, a worst case could be defined as one having the lowest level of voltage without protection (the first level undervoltage relay setting) for the maximum time duration (the time delay setting for the second level undervoltage relay).

From a probabilistic standpoint, however, it is highly unlikely that this will be the case. With the very small degraded voltage-to-operating voltage margins that exist at most nuclear units, the most likely degraded voltage scenario is one wherein voltage falls only marginally below the second level undervoltage relay setpoint. Just as likely, following large motor starts, bus voltage might return to a level above the setpoint but not sufficiently above that level to reset the dropped out voltage detection device(s). When small margins are involved, such issues as relay drop-out-to-pickup ratios become an issue. Your comment reveals the need for more discussion in our document in this area. Our revisions will seek to provide guidance as to a means for calculating a degree of voltage degradation that is both conservative and reasonable.

We do not agree that emergency diesel generator (EDG) starts of motors should be viewed as degraded, even though allowed momentary voltage and frequency swings are significantly outside of NEMA MG 1 limits. Experience shows EDGs to be excellent suppliers of stand-alone power for the starting of motors. This is due to the use of automatic voltage regulators and dynamic governors that serve to rapidly restore voltage and frequency to the set targets. For that reason, unless we identify evidence to the contrary, we will continue to consider the second start of equipment to be under normal power supply conditions.

Regarding the lack of mention in Section 2.3 "that switchyard voltage could drop immediately following the trip of the plant's generator due to the loss of the generator's MVAR support to the grid," we note that an immediate drop, while likely, would not represent a worst case since the second level undervoltage relay timers would likely start immediately as opposed to being delayed in their start, a condition which we believe does represent the worst case. We agree that a worst case for one condition (an untimely interruption in coolant injection flow) may not be a worst case for another condition (like the first start of motors occurring with a degraded voltage). The vast number of combinations and permutations for event development makes the use of judgment in some areas unavoidable. We will include some discussion on this subject in both Section 2.3 and when specifically addressing motor starts.

c) *On page 7-9 of the report, Note 4 states that motors are nominally designed for a life of from 20 to 40 years and, in many applications have, with reasonable preventive maintenance, lasted significantly longer than the design life. Note 4 should acknowledge that the majority of plants will be operating for 60 years under license renewal and address the consequences of this on motor design life.*

Response:

We concur with your comment and note that individual nuclear unit owners will always have the responsibility for evaluating the impact of life extension initiatives on their equipment using available guidance such as this double sequencing document. We will revise the report to acknowledge the likelihood of most plants operating for 60 years and provide some of the generic reasons why motors may be acceptable for life extension given their relatively mild service environment, low number of starts, routine preventive maintenance etc.

d) On page 7-11, Note 4 references Table 7-3 data from Millstone and states that sizeable safety margins are evident between the inertia the motors could accelerate to rated speed and the inertia of the actual plant loads. Are the actual plant load inertias provided in Table 7-3, the inertia with the pump discharge valves initially in the closed or open position? During double sequencing, the first pump start will typically be with the pump discharge valves in the closed position resulting in low load inertia; but during the second pump start the valves will likely be in the fully open position resulting in high load inertia. This issue was identified during an Advisory Committee on Reactor Safeguards (ACRS) hearing on delayed LOOP, and the ACRS indicated that the design of the pumps generally only provide for starting of the pump against a closed discharge valve.

Response:
NRC is correct in alluding to the fact that the motor's output capacity (torque) will, in part, be consumed by accelerating and moving the pumped (or compressed) media if a valve (or damper) is open, and flow allowed. Regarding safety margins between load and motor torque requirements and capability, respectively and the issue of pump starts with discharge valves in the wrong position, we note that a properly designed pump motor start control circuit includes interlocks to preclude starts under incorrect discharge valve lineups when valve position is important.

A Service Water Pump (SWP) at one of the pilot units is a good example for discussion and will be considered for inclusion in the report. In this case, SWP motor starts are supervised by valve position; i.e., the start circuit is not satisfied without the valves first returning to their required position. A shutdown of the motor whether manually or by way of a LOOP-induced trip, is followed by automatic valve repositioning prior to its restart permissive being satisfied.

Finally, while we agree that load inertia is a factor that affects acceleration time, it is the BWROG's position that "built-in" inertia (like that presented by the mass and diameter of a large fan blade set) represents the greatest opposition to acceleration during the lowest motor torque capability rotational speed region. We note that the load, air in this example case, presents a resistance to acceleration (inertia) that is not in any respect directly proportional to fan speed, but rather, is considerably less than directly proportional. In fact, as the motor and fan approach operational (rated) speed, the induction motor finds itself with its greatest operational torque capability since it is in the "pull-in" torque region of the associated torque versus rpm curve. While we believe that this consideration markedly reduces any concern related to "load" induced inertia, we will none-the-less speak to this point in our revisions to the document(s).

11. <u>Page 7-6 – Table 1, Item 5 and its associated Note 4</u>

This item evaluates 4kV fan motors. Comment 10a above applies.

Response:

Our response to Comment 10a applies to this comment as well.

12. <u>Page 7-6 – Table 7-1, Item 8 and its associated Note 7</u>

This item evaluates 480V load center switchgear and breakers. Comment 7 above applies to 480V breakers that are load sequenced.

Response:

Our response to Comment 7 applies to this comment as well.

13. *Page 7-6 –Table 7-2, Item 10 and its associated Note 9*

This item evaluates 480V load control center switchgear and breakers. Comment 7 above applies to 480V breakers that are load sequenced.

Response:

Our response to Comment 7 applies to this comment as well.

14. Page 7-6 – Table 7-2, Item 10 and its associated Note 9

This item evaluates 125Vdc control power for 480V load control centers. Comment 6 above applies.

Response:

Our response to Comment 6 applies to this comment as well.

15. Page 7-6 – Table 7-1, Item 11 and its associated Note

This item evaluates 480V load center powered pump motors. The number of the note associated with it appears to be in error. The staff believes Note 4 was intended. Comments 10a, b, c, and d above apply.

Response:

We understand that the equipment numbers in the Table are not appropriately indexed to the notes. In addition to correcting this overall condition, we will also correct the note numbering error that you have identified when we revise the document. Our responses to Comments 10a, b and c apply to this comment as well.

16. Page 7-7 – Table 7-1, Item 12 and its associated Note 4

This item evaluates 480V load center powered fan motors. Comment 10a above applies.

Response:

Our response to Comment 10a applies to this comment.

17. Page 7-7 – Table 7-1, Item 13

This item evaluates 480V motor control centers molded case circuit breakers. No note is associated with this item, but it appears Note 10 was intended to apply.

Response:

We will correct this omission.

18. Page 7-7 – Table 7-1, Item 14 and its associated Notes 10 & 11

This item evaluates 480V motor control center protective relaying. It appears that only Note 11 applies to this item and Note 10 was intended to apply to Item 13. Note 11 states that double sequencing will not cause improper operation of thermal overload protectors if these relays are set in accordance with standard industry practice. The staff does not believe this is necessarily true, particularly if the double sequencing is due to degraded voltage. Comment 10b above discusses the degraded voltage scenario. The double sequencing, in combination with the prolonged inrush current during the first degraded voltage start, could cause actuation of thermal overload protectors due to the excessive pre-heating of the thermal element during the first start. Comment 8 above also applies.

Response:

We will correct the notation error. The document will be expanded to cover this issue and the potential need for unit-specific sensitivity checks of bounding motor/load thermal overload combinations. Our response to Comment 8 is closely related to this comment.

19. Page 7-7 – Table 7-1, Item 17 and its associated Note 13

This item evaluates 480V MOV reversing and non-reversing contactors. The associated Note 13 addresses the high continuous inrush current that can flow to the coils of motor starters during a sustained degraded voltage condition. It describes fuse blowing experiment results at Millstone that found properly sized fuses remained intact with inrush current flowing from 40 to 60 seconds. Degraded voltage relay time delays have typically been chosen to be short enough to preclude the fuses from blowing, but did not consider the second additional short reenergization and inrush that would occur during double sequencing initiated by a degraded voltage condition. Degraded voltage relays, particularly those with longer time delays, should be evaluated to ensure the second reenergization will not blow the fuse.

Response:

We concur with your observation that most second level undervoltage time delays have been selected to be sufficiently short to avoid the potential for blowing control circuit fuses due to the sustained inrush current demand of a starter contactor that has insufficient voltage to pick up. However, lacking assurance that this is the case across the industry, we will add a reminder that fuse sizing criteria and second level undervoltage time delay need to be evaluated on a unit-specific bounding case basis.

We do not, in general, agree that the second contactor pickup demand has the potential to blow the fuse even if only minor fuse opening margin remains after the first attempt. This is due to the fact that a contactor, when energized with acceptable voltage (which it will have on the second position change demand) changes state in a matter of a few electrical cycles, at most. A second pickup demand occurring simultaneous to a voltage dip caused by a large motor start would, at most, expose the contactor and fuse to a few second period of inrush current. We will discuss the need to consider this potential in our revisions to the document.

20. Page 7-7 – Table 7-1, Item 18 and its associated Note 14

This item evaluates short duty cycle (15 minute) motors. The associated Note 14 states that even in the most severe applications, several strokes from one position to the other can be completed without violating the 15-minute criteria. The Note does not address double sequencing that is initiated by a degraded voltage. In this scenario, the MOV motor inrush and operating cycle during the first degraded voltage start can be excessively long since the motor torque is a direct function of the applied V^2. During the second sequence, if the MOV has not fully cycled, there will be a second motor inrush. This could potentially trip the motor overload protection and should be evaluated. Comment 18 above also applies.

Response:

This comment and Comments 12d and 18 relate to the type of motors used to power Motor Operated Valves (MOVs). We agree with your observation relative to prolonged starts and the potential to trip the thermal overload. Our report will be modified to note that for nuclear units wherein the thermal overloads are not bypassed either full time or upon occurrence of an accident event per NRC guidance, a review of a bounding case will be necessary to determine if the thermal overload is appropriately sized.

21. Page 9-2 – Recommendation 5

This recommendation provides guidance on how probabilistic risk assessment organizations can use the EPRI report and any input from their safety analysis personnel to determine if there is a need to update probabilistic safety analysis models to include double sequencing. It indicates that increasing the failure probability of the diesel generators and the grid-related LOOP initiating frequency are two approaches to modeling the risk impact of double sequencing in plant-specific probabilistic risk assessment (PRA) models, and those can easily be implemented in the nuclear plant equipment out-of-service computer program. The staff does not agree with this view and would reject an analysis that used only these approaches.

NUREG/CR-6538, "Evaluation of LOCA with Delayed LOOP and LOOP With Delayed LOCA Accident Scenarios," found that in 1997 nuclear plant individual plant evaluations (IPEs) do not model nor do they discuss LOCA with consequential or delayed LOOP. Increasing grid-related LOOP initiating event frequencies in plant-specific PRAs or EOOS programs would therefore provide no insight into the risk impact of double sequencing scenarios, but would only indicate the risk impact of station blackout scenarios which are typically the events LOOP frequencies are used for. In fact, LOOP initiating event frequency is not the parameter of interest in double sequencing scenarios (see Comment 2, above). Conditional probability of LOOP given a LOCA, or consequential LOOP for short, is the parameter of interest. This is supported by the discussion in Section 1.1 of the EPRI report under the topic of "Probability of Double Sequencing at Domestic Nuclear Power Plants." A comprehensive discussion of consequential LOOP can also be found in Appendix G of a July 31, 2002, NRC Office of Research memorandum located in the NRC Agencywide Documents Access and Management System (ADAMS) at Accession No. ML022120661.

Increasingly the failure probability of the diesel generators, which is the second proposed approach, is only a portion of the vulnerability of double sequencing scenarios. A PRA should consider the other equipment vulnerabilities addressed in the EPRI report as amended by the totality of these NRC comments. If the vulnerabilities do not make the particular safety equipment unavailable altogether, the analysis should consider how the equipment failure rates would increase under the double sequencing

scenario conditions and stresses.

Response:

There are many points for discussion relative to this comment. Regarding the approaches to PRA adjustment that we suggested, we concur that, if it cannot be shown that double sequencing will not increase the likelihood of failure of accident mitigation equipment, these approaches are not the right ones. Our view of this matter is that minor additional degradation related to equipment exposure to infrequent and perhaps, one-time conditions cannot be quantified and might very well be undetectable as to its impact on equipment reliability. We believe that the revisions to this document occurring as a result of your comments have the potential to change the NRC's outlook as to the acceptability of the proposed PRA approach. It is also possible that our work involved in revising the document as a result of your comments will result in a change to our proposed approach.

It is key, however, that licensees be able to confidently establish that a double sequencing event will not invalidate compliance with the single failure criterion for a common mode condition; i.e., double sequencing. In most cases, redundant and independent equipment divisions are identically designed and constructed. As an example, if a double sequencing event causes a fuse of proper size and in proper condition to blow in the MCC control circuit of a Train A critical MOV control circuit due to the inability of its starter contactor to pickup, then it is logical that it will blow the fuse in the Train B MOV circuit as well. Your reviewers say it well in the last paragraph of this comment wherein they state that "If the vulnerabilities do not make the particular safety equipment **unavailable altogether** [emphasis added], the analysis should consider how the equipment failure rates would increase under the double sequencing scenario conditions and stresses." Redundant divisions' being "unavailable altogether" is a condition that would be unacceptable and is the key consideration for evaluation when addressing the double sequencing issue. Minor accelerated aging type of degradation to properly maintained equipment for a potential one-time event is not the substantive double sequencing issue.

Regarding the issue of "conditional probability" and as noted earlier in our responses, we will refrain from using that terminology since a double sequencing event can only occur if there is a safeguards actuation and otherwise has no meaning.

EPRI Technical Report 1007966

1. General

The comments provided for EPRI Report 1009110, Revision 1, "The Probability and Consequences of Double Sequencing Nuclear Power Plant Safety Loads," apply equally to this report and boiling water reactors (BWRs) in general, since the electrical equipment in BWRs is not substantially different from pressurized water reactor designs.

Response:

We agree that, with minor exceptions, the NRC's comments on the more comprehensive Report 1009110, Revision 1 are equally applicable to BWRs. An example of one exception is the discussion of the 30-second time delayed trip of the main generator in PWR plants included in your Comment 4.

We note that, while much of the basic equipment is similar if not identical, and could have been installed in a PWR or a BWR, the BWR design inherently requires a much smaller subset of equipment to operate to mitigate the consequences of the entire range of design basis accidents.

2. *Page 7-3 –Discussion in Section 7.4*

In this discussion it is indicated that BWR/6 designs have additional margin and are less affected by double sequencing because they have a dedicated diesel generator for the HPCS system. It is not clear if these conclusions recognize that the HPCS is normally powered from offsite power and is powered from its diesel only when offsite power is lost. It is therefore subject to energization and reenergization similar to double sequencing. There is also at least one BWR/6 plant that has a short sequence of an HPCS pump and a cooling water pump on the HPCS diesel generator, which would make it even a bit more like the double sequencing designs.

Response:

We will research this comment and revise the document as appropriate.