OG-02-052
November 27, 2002

WCAP-15622, Rev. 0
Project Number 694

Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Attention: Chief, Information Management Branch,
Division of Inspection and Support Programs

Subject: Westinghouse Owners Group
Transmittal of RAI Responses for WCAP-15622, "Risk-Informed Evaluation of Extensions To AC Electrical Power System Completion Times" (MUHP-3010)

References:
1. WOG Letter, R. Bryan to Document Control Desk, "Transmittal of WCAP-15622, 'Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times,' OG-01-039, June 15, 2001.

2. NRC Letter, D. Holland to G. Bischoff, "Westinghouse Topical Report, WCAP-15622, Rev. 0, 'Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times', Request for Additional Information (TAC No. 2257)."

3. NRC Letter, D. Holland to G. Bischoff, "Westinghouse Topical Report, WCAP-15622, Rev. 0, 'Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times'," January 15, 2002.

In June 2001, the Westinghouse Owners Group submitted WCAP-15622, Rev. 0, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" for approval (Ref. 1). In January 2002, the NRC issued Requests for Additional Information (RAIs) concerning WCAP-15622, Rev. 0 (Refs. 2 & 3). Attachments 1 & 2 provide the WOG responses to the RAIs.

If you require further information, feel free to contact Mr. Ken Vavrek, Westinghouse Owners Group Project Office at 412-374-4302.

Very truly yours,

Robert H Bryan

Robert H. Bryan, Chairman
Westinghouse Owners Group

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cc: WOG Steering Committee
WOG Primary Representatives
WOG Licensing Subcommittee Representatives
G. Shukla, USNRC OWFN 07 E1 (2L, 2A) (via Federal Express)
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Responses to NRC Request for Additional Information

NRC Letter, D. Holland to G. Bischoff, "Westinghouse Topical Report, WCAP-15622, Rev. 0, 'Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times', Request for Additional Information (TAC No. 2257)."

These RAIs have been divided into four groups depending on the subject of the RAI, the type of response required, and the approach to the response. The following defines the groups and the RAIs within each group, and the overall approach to the RAI response.

<u>Group 1 RAIs</u>

- Generic responses are required
- RAIs 4, 11 (plant specific information also required), 12, 14, 15, 17, 18, 19
- Responses to these RAIs are provided on the following pages.

<u>Group 2 RAIs</u>

- Plant specific responses are required to issues directly related to the WCAP-15622 analysis or information provided in WCAP-15622.
- RAIs: 3, 8, 9, 13, 16
- Responses to these RAIs are provided on the following pages

<u>Group 3 RAIs</u>

- Plant specific responses are required to issues not directly related to the WCAP-15622 analysis or information provided in WCAP-15622 (this refers to information related to NRC Information Notices, Regulatory Guide requirements, etc.).
- RAIs: 2, 5, 6, 7, 10, 11 (generic response also provided)
- Responses to these RAIs will be provided by utilities in their License Amendment Request (LAR) submittals following approval of WCAP-15622.

<u>Group 4 RAIs</u>

- RAI issue is outside the scope of the program.
- RAIs: 1
- Response to this RAI will be provided via other industry issue resolution approaches.

It should be noted that not all the utilities that provided plant specific information for WCAP-15622 were able to support responses to these RAIs (Group 2 RAIs to be specific). Therefore, the responses to Group 2 RAIs are limited to the utilities that currently have the resources to support the responses These utilities, and plants, are:

- AmerenUE, Callaway
- Duke, McGuire
- TVA, Sequoyah
- TXU, Comanche Peak

The remaining plants/utilities initially included in WCAP-15622 (Ginna/RG&E, Summer/SCE&G, Catawba/Duke, Shearon Harris/CP&L) will provide plant specific responses to Group 2 RAIs (and Group 3 RAIs, if applicable) with their LAR submittal following approval of WCAP-15622. These responses will be consistent with the responses to the Group 2 RAIs on the following pages.

Licensees for plants not included in this WCAP-15622, but that request these completion time (CT) extensions and reference WCAP-15622 approach, will need to follow revised WOG guidance on 1) the required analysis and 2) information required to be provided to the NRC for review in the plant specific LARs. The revised guidance and information to be submitted will be consistent with the current review of WCAP-15622. That is, the information requested in these RAIs will also be required in future licensee LAR submittals

Please note that throughout these responses the terms repair and scheduled activities are typically used. A repair activity is equivalent to a corrective activity, and a scheduled activity is equivalent to a preventive or a planned activity.

Responses to NRC Request for Additional Information

NRC Letter, D. Holland to G Bischoff, "Westinghouse Topical Report, WCAP-15622, Rev. 0, 'Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times', Request for Additional Information (TAC No. 2257)."

RAI 1:A review of the proposed technical specifications (TSs) shows that condition A.3 and B 4 extend the discovery of failure to meet the limiting condition for operation (LCO) from 6 days to 10 days. The 10-day value is based on the proposed 7-day diesel generator (DG) completion time and a proposed 72-hour completion time for ACTION B.3 The NRC staff is concerned that the 10-day completion time for discovery of meeting the LCO has not based on a risk perspective, but simply reflects an adaptation of the TS to the proposed 7-day DG completion time. The NRC staff notes a similar situation with the proposed 34-hour completion time for LCO 3.8.9. Required Action A 1, "Restore the AC electrical power distribution system(s) to OPERABLE status," Required Action B 1, "Restore AC vital bus subsystem(s) to OPERABLE status," and Required Action C.1, "Restore the DC electrical power distribution system(s) to OPERABLE status" The 34-hour completion time for discovery of not meeting the LCO has not been based on a risk perspective, but simply reflects an adaptation of the TS to the 8-hour AC power distribution system, plus the 24-hour AC vital buses, plus the 2-hour DC electrical power distribution subsystems being inoperable Provide a discussion for the basis for the proposed 10-day and 34-hour completion times that does not rely solely on engineering judgement.

Response: The industry submitted NEI Technical Specification Task Force (TSTF) Traveler TSTF-439 "Eliminate Modified Time Zero Completion Times" on June 6, 2002 to address this issue. This RAI will be addressed by TSTF-439 and not as part of the staff's review of WCAP-15622.

RAI 2. The staff noted that WCAP-15622 review methodology does not include probabilistic risk assessment (PRA) quality criteria for the evaluation of AC electrical power source completion times. Discuss PRA quality measures, including peer reviews, and how WCAP-15622 addressed individual plant PRA quality for the proposed plants and PRA quality guidance for subsequent plant specific submittals, including those plants not included in WCAP-15622.

Response: The detailed response to this RAI will be provided in each licensee's License Amendment Request (LAR) following the NRC's approval of the changes proposed in WCAP-15622. To address this issue, each licensee requesting the changes proposed in this WCAP, those included in the WCAP and those referencing the WCAP in future LARs, will provide a discussion of the following:

- Utility's PRA quality program and how it ensures that the model represents the as-built, as-operated plant.
- IPE findings, related to the AC systems, and how they were addressed.
- Peer review findings, related to the AC systems, and how they were addressed If the peer review findings, related to the AC power system, have not yet been addressed, the possible impact of these findings on the results presented in WCAP-15622 will be discussed.
- Findings of any other PRA reviews, related to the AC systems, and how they were addressed

RAI 3. In Section 8.2.3.5, "Shearon Harris Results Discussion" states that the station blackout (SBO) core damage frequency (CDF) contribution with a 72-hour completion time is 1.34E-05/yr and that the contribution with a 7-day completion time is 1.36E-06/yr. The WCAP states that the increased value of 1.36E-06 is due to additional activities expected to be performed while at power. Reconcile the values given for SBO in Section 8.2.3 5.

Response: An incorrect value was provided for the SBO contribution with a 7-day CT. The value provided in the WCAP, as noted above, is 1.36E-06/yr. The correct value is 1 36E-05/yr.

RAI 4. WCAP-15622 provides a discussion on the sensitivity of the reactor coolant pump (RCP) seal models based on the topical report (TR) results. The Brookhaven National Laboratory loss-of-coolant accident (LOCA) seal model was used with modifications (WOG model) to address the importance of the LOCA seal model on the CDF analysis. At present, the Rhodes LOCA seal model is the model approved by the staff. Under certain circumstances, the use of the Rhodes model may yield significant differences in the PRA results. Provide a discussion on the CDF contributions when using the Rhodes model (SBO) and the effect on the conclusions stated in WCAP-15622.

Response: First, it should be noted that the plants included in this WCAP use the same RCP seal leakage models in their PRA models that have been used by other licensees that have requested, and the NRC has approved, DG CT extensions. Therefore, there is nothing unique about the RCP seal leakage models used by the utilities included in this WCAP.

Second, the NRC has issued the memorandum "Implications of Using Rhodes RCP Seal LOCA Model in Risk Assessments" dated May 1, 2001 to inform Standardized Plant Analysis Risk (SPAR) model users and other agency risk analysts about the implications of using the "Rhodes Model" to model reactor coolant pump seal loss-of-coolant accidents. It was concluded in this memorandum that:

- The risk significance associated with some initiators that result in loss of RCP seal cooling (e g., loss of component cooling water, loss of service water) is substantially affected when the Rhodes model is used.
- The conditional core damage probability (CCDP) associated with loss of offsite power (LOSP) did not change significantly for the four plants analyzed In Attachment 2 to this memorandum, it states that the CCDP either decreased slightly or showed no discernible change.

The memorandum also notes that two known circumstances under which the CCDP may change significantly are:

- LOSP events at plants (such as Oconee) where the emergency feedwater (EFW) can be supplied from sources unaffected by the station blackout (e.g , a dedicated safety shutdown facility, crossties from other units),
- LOSP events where offsite power can be recovered before the battery-depletion-time following an RCP seal LOCA.

The memorandum does not explain why the CCDP may change significantly under these circumstances. But in both cases it appears that EFW continues to run and remove decay heat, but cooling to the seals is not restored In the first case, EFW is supplied power from an alternate source that is not impacted by the LOSP/SBO In the second case, DC control power to the EFW (turbine-driven) pump is available so EFW continues to run, and when offsite power is recovered the motor-driven feedwater pumps become available. In either case, the SBO core damage sequences do not appear to be dominated by loss of decay heat removal, but by RCP seal LOCAs. In these situations the RCP seal leakage model may have a larger impact on CDF since this type of core damage sequence dominates

Third, a sensitivity study was completed using the PRA model for a Westinghouse plant with reactor coolant pumps containing the older type of O-rings This plant does not have an alternate source of power dedicated to EFW for SBO events The analysis was completed for the following three situations:

- Base Case. 8 hour diesel generator mission time, no alternate source of AC power
- Sensitivity Case 1 2 hour diesel generator mission time, no alternate source of AC power

- Sensitivity Case 2: 2 hour mission time, alternate AC source of power that can provide power to the safety buses

The impact of the CT extension on CDF was re-evaluated using the following three RCP seal leakage models for each case listed above:

- Rhodes model as defined in NUREG/CR-5167 ("Cost/Benefit Analysis for Generic Issue 23. Reactor Coolant Pump Seal Failure", April 1991)
- Brookhaven model as defined in BNL Technical Report W6211-08/99 ("Guidance Document for Modeling of RCP Seal Failures", August 1999)
- WOG/Westinghouse model as defined in WCAP-10541 ("Reactor Coolant Pump Seal Performance Following a Loss of All AC Power", November 1986) This model is used in a number of plant PRA models.

Tables RAI 4-1, RAI 4-2, and RAI 4-3 provide the results of this analysis Tables RAI 4-1 and RAI 4-2 provide the probabilities for uncovering the core with and without RCS cooldown for the WCAP-10541, Brookhaven, and Rhodes RCP seal leakage models The WCAP model provides lower core uncovery probabilities than the other two models later in the event and higher core uncovery probabilities earlier in the event.

Table RAI 4-3 provides the core damage frequency results for the three cases listed above for the three RCP seal leakage models The WCAP-10541 RCP seal leakage model provides slightly lower core damage frequency values and a slightly smaller impact on CDF with the extended CT. Based on this it is not expected that the RCP seal LOCA model used will have any significant impact on the results or conclusions of this analysis

Table RAI 4-1
Probabilities for Uncovering the Core with RCS Cooldown

Time (hours)	WCAP-10541	Brookhaven	Rhodes
1	2.83E-02	5 00E-03	0
4	2.83E-02	1 57E-02	5 00E-03
6	1.10E-01	8 08E-01	1 0
10	2 75E-01	9 08E-01	1.0
12	3 42E-01	9.19E-01	1.0
14	3 96E-01	9.26E-01	1.0

Table RAI 4-2
Probabilities for Uncovering the Core without RCS Cooldown

Time (hours)	WCAP-10541	Brookhaven	Rhodes
1	2.83E-02	5.00E-03	0
4	3.45E-02	7.87E-02	9.83E-02
6	2.32E-01	1.0	1.0
10	4.57E-01	1.0	1.0
12	5.15E-01	1.0	1.0
14	5.56E-01	1.0	1.0

Table RAI 4-3
Summary of CDF Impact for Various RCP Seal Leakage Models

Case	RCP Seal LOCA Model		
	WCAP-10541	Brookhaven	Rhodes
Base Case (8 hour DG mission time, no alternate AC power source)			
• CDF (3 day CT)	5.595E-05	5 871E-05	5.779E-05
• CDF (7 day CT)	5.688E-05	5 979E-05	5.886E-05
• ΔCDF	9.30E-07	1 08E-06	1.07E-06
Sensitivity Case 1 (2 hour DG mission time, no alternate AC power source)			
• CDF (3 day CT)	2.818E-05	2.659E-05	2.582E-05
• CDF (7 day CT)	2.855E-05	2.702E-05	2 624E-05
• ΔCDF	3 70E-07	4.30E-07	4.20E-07
Sensitivity Case 2 (2 hour DG mission time, alternate AC power source)			
• CDF (3 day CT)	1.994E-05	1.716E-05	1.644E-05
• CDF (7 day CT)	2 005E-05	1 729E-05	1.657E-05
• ΔCDF	1.10E-07	1.30E-07	1 30E-07

RAI 5. Information Notice 97-02, "Availability of Alternate AC Power Source Designed for Station Blackout Event" addressed potential unavailability of alternate AC power sources and noted that the capability to start on demand depends on the unavailability of support systems that may require AC or DC power. Determine the applicability of information notice 97-02 to WCAP-15622 review methodology and implementation guidelines.

(Note that Information Notice 97-02 is "Cracks Found in Jet Pump Riser Assembly Elbows at BWRs". Information Notice 97-21 is "Availability of Alternate AC Power Source Designed for Station Blackout Event". Information Notice 97-21 is the document applicable to this WCAP.)

Response: The detailed response to this RAI will be provided in each licensee's LAR following the NRC's approval of the changes proposed in WCAP-15622. To address this issue, each licensee requesting the DG CT extension proposed in this WCAP that is crediting an alternate AC power source, those currently included in the WCAP and those referencing the WCAP in future LARs, will provide a discussion on the applicability of this Information Notice Note that Catawba and McGuire are the only plants currently included in the WCAP that credit an alternate AC power source

RAI 6. Provide the values for emergency diesel generator (EDG) reliability and unavailability used in the PRA calculations including SBO (include alternate AC source if applicable). Discuss these values in relationship to the maintenance rule implementation goals and comparison to actual EDG performance and SBO commitments Discuss incorporation into WCAP-15622 implementation guidelines.

Response: Table 8-2 of WCAP-15622 provides the EDG reliability information in terms of fail to start and fail to run values. Section 8.2.1 of WCAP-15622 provides a discussion on how the maintenance unavailabilities (EDG maintenance outage time) is expected to be impacted with the CT extension.

The additional information requested regarding the Maintenance Rule implementation goals, and comparison of actual EDG performance and SBO commitments (including the alternate AC source if applicable) will be provided in each licensee's LAR following the NRC's approval of the changes proposed in WCAP-15622. To address this issue, each licensee requesting the DG CT extension proposed in this WCAP, those currently included in the WCAP and those referencing the WCAP in future requests, will provide the following.

- EDG fail to start and fail to run values
- EDG maintenance unavailability with 3 day CT and with 7 day CT
- Alternate AC source failure probability values (if applicable)
- Alternate AC source maintenance unavailability (if applicable)
- Short discussion with regard to these values relative to Maintenance Rule goals, actual EDG performance, and SBO commitments.

RAI 7. For plants that take credit for an alternate AC source, provide a discussion on the vulnerability of the alternate AC source to external events (including weather-related events) that could disable the alternate AC power source, the emergency AC power source, or the normal offsite power sources. Include common cause failure mechanisms between the normal electrical distribution system and the alternate AC source. Discuss the impact of external events on the availability of alternate sources of AC power (SBO diesels for example) with respect to WCAP-15622 and the included implementation guidelines Provide a discussion as to the assumptions (qualification) and risk impact of the alternate AC source

Response: The detailed response to this RAI will be provided in each licensee's LAR following the NRC's approval of the changes proposed in WCAP-15622 To address this issue, each licensee requesting the DG CT extension proposed in this WCAP that is crediting an alternate AC power source, those currently included in the WCAP and those referencing the WCAP in future requests, will provide a discussion on the vulnerability of their alternate AC power source to external events as requested above Note that Catawba and McGuire are the only plants currently included in the WCAP that credit an alternate AC power source.

RAI 8. The results for Delta CDF and incremental conditional core damage probability (ICCDP) shown in Table 8-1, Table 8-5 and Table 8-6 are not consistent with the Regulatory Guide (RG) 1.174 , "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and RG 1.174 (correction, 1.177), "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications" guidance. Numerous results show what appears to be substantial differences from the guidelines Discuss these differences and include any compensatory measures (or guidance) before and during diesel generator maintenance or AC bus restoration including 10 CFR 50 65 maintenance rule provisions or surveillances to be performed to ensure operability of systems associated with the remaining equipment (EDG, AC Bus). Include how these measures will be documented. Discuss any suggested revisions to the requested LCOs that will bring impacts into alignment with RG 1 174 and RG 1.177 guidelines or propose an alternate basis for acceptability

Response: Not all the results presented in the WCAP differ substantially from the acceptance guidelines provided in RG 1.174 and RG 1 177 A review of the results provided in WCAP-15622 shows that:

DG CT extension

- CDF impact ≤ 1 0E-06/yr is met for McGuire, Shearon Harris, and Summer
- ICCDP (schedule activities) ≤ 5E-07 is met for none of the plants
- ICCDP (repair activities) ≤ 5E-07 is met for none of the plants

DG common cause failure (CCF) CT extension

- CDF impact ≤ 1.0E-06/yr is met for Catawba, Ginna, McGuire, Sequoyah, and Shearon Harris
- ICCDP (schedule activities) ≤ 5E-07 is not applicable (CCF are only relevant to repair activities)
- ICCDP (repair activities) ≤ 5E-07 is met for McGuire and Sequoyah

Based on these results, McGuire and Sequoyah meet the RG criteria impacts related to core damage frequency

AC Vital bus CT extension

- CDF impact ≤ 1.0E-06/yr is met for Catawba, Ginna, McGuire, and Sequoyah
- ICCDP (schedule activities) ≤ 5E-07 is met for Catawba, Ginna, McGuire, Sequoyah, and Summer
- ICCDP (repair activities) ≤ 5E-07 is met for Sequoyah, and close for Catawba and McGuire

Based on these results, Catawba, McGuire, and Sequoyah meet, or are very close to meeting, the RG criteria related to core damage frequency

The utilities with plant specific information included in the WCAP have reviewed their results and are reconsidering their CT extension requests. Several changes to the analyses have been considered and implemented These include

- Revised analyses based on updated PRA models
- Revised analyses crediting reduced LOSP frequencies during maintenance activities (Note that this approach is only used for plants that need to 1) credit restrictions on plant activities concurrent with DG outages and/or 2) restrict DG outages to times of high grid reliability to meet the risk acceptance criteria in Regulatory Guides 1 174 and 1.177. This is discussed in more detail below)
- Reduced CT extension requests
- Shorter CT extension requests for the higher importance buses

The analysis changes implemented by each licensee are plant specific and are discussed with the plant specific revised results on the following pages

Reduced LOSP frequencies during maintenance activities

For scheduled DG maintenance activities and repairs that follow scheduled test activities it is possible to control other plant activities that are scheduled and also the time of the year when the activity is planned Control of these elements can result in a reduced probability of a loss of offsite power event when scheduled DG maintenance activities are in progress. Restrictions can be placed on:

- Concurrent (with the DG outage) electrical switchyard activities
- Concurrent (with the DG outage) activities that can impact the reliability of the electrical switchyard
- Access to the electrical switchyard
- Time of the year when the activity is scheduled

An approach was developed for utilities to use to calculate a plant specific LOSP initiating event frequency for scheduled maintenance activities This approach requires a review of the LOSP events that have occurred along with a plant specific assessment of the applicability of these events given the possible restrictions listed above Based on this review and the restrictions utilities will put in place when in an extended DG outage for a scheduled activity, a number of LOSP events can be eliminated from the database Based on the remaining events, a generic LOSP initiating event frequency can be calculated for scheduled maintenance activities. This generic value can then be Bayesian updated with plant specific experience. The steps in this process are:

1: Identify Plant Restrictions
2: Assess the Applicability of Plant-Centered Events
3: Assess the Applicability of Grid-Related Events
4: Assess Applicability of Weather-Related Events
5 Calculate Generic LOSP IE Frequency
6 Calculate Plant Specific LOSP IE Frequency
7 Bayesian Update of Generic LOSP IE Frequency with Plant Specific Information

Several of the participating utilities used this approach to justify the extended CT for scheduled activities on the DGs. This approach may or may not result in a split Technical Specification CT; the current CT (72 hours) for repair activities and an extended CT (7 days or greater) for scheduled maintenance activities (or repair activities that follow scheduled test activities). This approach may also result in restrictions or preconditions when performing scheduled activities on the DGs These restrictions will be documented in plant procedures or through the plant specific configuration risk management program per (a)(4) of the Maintenance Rule

The revised results, with regard to core damage frequency measures, are discussed in the following paragraphs

Callaway: Revised CDF Related Results (DG CT Extension)

<u>Required Action, Restore (required) Diesel Generator to Operable Status</u>

Callaway is requesting the DG CT extension. The licensee has reconsidered the CT extension request with regard to its use. Callaway requests an extension of the CT for the DG to 11 days for only scheduled activities. The CT of 72 hours will remain applicable to repair activities The calculation to determine the impact of the CT increase is based on only scheduled activities using the extended CT. Repair type activities will continue to be limited to a 72 hour CT so there would be no impact on the DG unavailability related to repair activities.

The following restrictions, or preconditions, will be in place during scheduled DG maintenance activities.

- Procedure/controls will be put in place that restrict concurrent test and maintenance activities that could impact the reliability of the switchyard
- Procedure/controls will be put in place that restrict access to the switchyard
- The DG outage will be scheduled for a period of low power demand so that the grid reliability is high

Given these restrictions and the WOG approach for calculation of a plant specific LOSP initiating event frequency for scheduled maintenance activities, a revised LOSP IE frequency of 1.50E-02/year was determined Table RAI 8-1 summarizes the impact on CDF and the ICCDP values for the CT extension to 7 days and 11 days for scheduled activities

Table RAI 8-1 Callaway: Revised Results for the DG CT Extension		
Completion Time	**ΔCDF**	**ICCDP**
7 days	4.30E-07/yr	3.05E-07
11 days	6.76E-07/yr	4.79E-07

The ΔCDF and ICCDP values associated with the 11 day CT meet the guidelines in Reg Guides 1.174 and 1.177 of 1 0E-06/yr on CDF and 5.0E-07 on ICCDP

Based on this, Callaway is requesting an 11 day CT for scheduled type activities. The CT for repair type activities will remain at 72 hours

Comanche Peak: Revised CDF Related Results (DG CT Extension)

<u>Required Action, Restore (required) Diesel Generator to Operable Status</u>

Comanche Peak 1 and 2 is requesting a DG CT extension to 7 days for both scheduled and repair type activities Activities will be planned with the following restrictions, or preconditions, in place during the activity

- Procedure/controls will be put in place that restrict concurrent test and maintenance activities in the switchyard
- The DG outage will be scheduled for a period when no severe weather is forecast.

These restrictions apply to both scheduled and repair activities Historically, unplanned DG maintenance activities (repairs) follow tests on the DGs. The tests are planned activities and are subject to the above restrictions, therefore, if a test identifies a DG failure, then the repair activity that follows the test will be subject to the same restrictions as the test activity.

Given these restrictions and the WOG approach to calculation of a plant specific LOSP initiating event frequency, a revised LOSP IE frequency of 1.44E-02/year was determined. Table RAI 8-2 summarizes the impact on CDF and the ICCDP values for the CT extension to 7 days.

Table RAI 8-2 Comanche Peak: Revised Results for the DG CT Extension to 7 Days	
Parameter	**Value**
CDF (3 day AOT) (Baseline value)	1.67E-05/yr
CDF (7day AOT)	1.72E-05/yr
CDF Increase	4 87E-07/yr
CCDF (DG A in test or scheduled maintenance)	4 21E-05/yr
ICCDP (DG A in test or scheduled maintenance)	4.87E-07
CCDF (DG A in repair)	4 75E-05/yr
ICCDP (DG A in repair)	5.91E-07
CCDF (DG B in test or scheduled maintenance)	4 20E-05/yr
ICCDP (DG B in test or scheduled maintenance)	4.85E-07
CCDF (DG B in repair)	4 76E-05/yr
ICCDP (DG B in repair)	5.93E-07

- Values for both DGs are provided to demonstrate the minor asymmetries between DGs play no part in extending the CT.

The ΔCDF and ICCDP values meet the guidelines in Reg. Guides 1.174 and 1 177 of 1.0E-06/yr for CDF and 5.0E-07 for ICCDP for all parameters except for a DG in repair. The ICCDP values for a DG in repair are slightly greater than the 5.0E-07 guideline. But as noted in Regulatory Guide 1.177, the acceptance guidelines should not be interpreted as being overly prescriptive. The guidelines are intended to provide an indication, in numerical terms, of what is considered acceptable. As such, the numerical values are approximate values that provide an indication of the changes that are generally acceptable.

Based on this, Comanche Peak is requesting a 7 day CT for both scheduled and repair type activities

McGuire: Revised CDF Related Results (DG, DG CCF, and AC Vital Bus CT Extensions)

A revised set of results for the three CT extensions being considered for McGuire 1 and 2 are provided below based on their updated PRA model. There is no credit taken in the McGuire analysis for a reduced LOSP initiating event frequency during schedule maintenance activities

<u>Required Action, Restore (required) Diesel Generator to Operable Status</u>

Table RAI 8-3 provides the revised CDF related results for increasing the CT to restore an inoperable DG to operable status from 72 hours to 7 days This is consistent with the evaluation and results presented in the WCAP, that is, it does not restrict the CT extension to scheduled activities and does not credit restrictions on plant activities or place restrictions on the time of the year when performing maintenance activities. Table RAI 8-4 provides the revised set of parameters important to the analysis (comparable to the information provided in Table 8-2 for the WCAP)

WCAP-15622 originally stated that the extended CT will not be used to complete additional maintenance activities while at-power, but primarily used for corrective (repair) maintenance activities. On re-evaluation, the additional time may also be used to move DG testing currently performed during the outage to power operation In addition, the longer CT will allow the number of planned entries into the CT to decrease since multiple activities may be grouped together. As noted in the WCAP, it is estimated that the yearly downtime will increase from 91 hours to 175 hours per DG.

The ΔCDF and ICCDP values meet the guidelines in Reg Guides 1 174 and 1.177 of 1 0E-06/yr for CDF and 5.0E-07 for ICCDP. Based on this, McGuire is requesting a 7 day CT for both scheduled and repair type activities

The following additional information provided in Section 8 2.3 4 of the WCAP is updated as follows·

- Credit for electrical power cross connects: The plant is capable of cross-connecting the redundant 4160VAC safety buses between an alternate source on the same unit and from a source on the opposite unit This is modeled as an operator recovery action in the PRA model.

  The Operators are trained to perform these cross connections per approved procedures. At Catawba Nuclear Station, a sister plant to McGuire with similar power system design, licensed Operations personnel performed simulator runs and a plant walkdown for a scenario that required restoration of power from an alternate source via cross-connects. Current plant procedures cover this type of alignment It is not expected that there would any significant difference in the time to perform these cross connections between Catawba and McGuire.

  To estimate the credit taken for the crosstie on CDF, a sensitivity study was performed Removing credit for the crosstie resulted in a CDF of 2 94E-05/yr. The resulting CDF increase is 7.60E-06/yr

- Class 1E AC electrical power system design Same as in Section 8 2 3.4 of the WCAP

- Basis for LOSP IE frequency· Data are taken from EPRI 1000158, "Losses of Off-Site Power at U S Nuclear Power Plants- Through 1999". Twelve years of industry experience (1988-1999) are captured in the EPRI data There are 1254 industry generating years, excluding the 24 McGuire years during the EPRI data period During this period there were 37 industry LOSP events (excluding 4 that were not applicable to McGuire and 2 actual McGuire LOSP events). Based on this, the industry LOSP frequency excluding McGuire is 2.95E-02/yr This resulted in a Bayesian updated LOSP frequency for McGuire of 5 10E-02/yr at a 90% capacity factor.

- Loss of offsite power plant experience The same three events apply as discussed in Section 8 2 3.4 of the WCAP. These three events with an updated time period included in the analysis (through August 2002) results in a revised LOSP initiating event frequency.

- Reactor coolant pump seal LOCA model· The RCP seal leakage model is based on the WOG 2000 seal leakage model for high temperature O-rings (WOG document WCAP-15603, "WOG 2000 Reactor Coolant Pump Seal Leakage Model for Westinghouse PWRs"). The McGuire PRA model explicitly addresses a loss of RCP seal integrity due to cooling failure and the timing of diesel generator start and run failures Twelve unique recovery events are applied to the LOSP initiated, core melt sequences

  The probability of core uncovery from station blackout events is determined from data taken from WCAP-15603. For the worst case leak rate based on WCAP-15603, which had a probability of core uncovery of 2 5E-03, Modular Accident Analysis Program (MAAP) runs determined the time to core uncovery to be 1.5 hours Therefore, at 1 5 hours, the probability of core uncovery was 2.5E-03.

- Availability of alternate AC power source: The same as discussed in Section 8.2.3.4 of the WCAP with the following re-evaluation of the impact of crediting the alternate AC power source. A sensitivity study was performed to estimate the credit of the standby shutdown facility (SSF) DG.

Removing credit for the SSF DG resulted in a CDF of 2.74E-05/yr, as opposed to a base CDF of 2.18E-05/yr, which is an increase in CDF of 5 60E-06/yr.

- Station Blackout (SBO) contribution to CDF: The SBO contribution to CDF from the IPE is estimated to be 1.5E-05/yr The SBO contribution from the current base case plant PRA model is 1.31E-06/yr. This value is based on a 72 hour CT. The difference in values is due to 1) the IPE did not account for the difference in 1 or 2 unit LOSPs, therefore, the LOSP initiating event frequency in the IPE is overestimated, 2) the use of a lower capacity factor in the IPE, 3) the diesel generator failure rate used for the IPE reflected a period of poor equipment performance that does not exist today, and 4) the AC power recovery model makes use of recent LOSP recovery experience and incorporates the recent WOG RCP seal leakage model. The SBO contribution with a 7 day CT is 1.5E-06/yr. The increase is due to the additional activities expected to be performed while at power. The DG fail to start and fail to run values used in the IPE are 6.0E-03/d and 7.9E-03/hr, respectively. The LOSP initiating event frequency used in the IPE was 7 0E-02/yr.

Table RAI 8-3
McGuire: Revised Results for the DG CT Extension to 7 Days

Parameter	Value
CDF (72 hr CT)	2.18E-05/yr
CDF (7 day CT)	2 20E-05/yr
CDF Increase	2.10E-07/yr
CCDF (DG in test or scheduled maintenance)	3 93E-05/yr
CCDF (DG in repair)	5 17E-05/yr
ICCDP (DG in test or scheduled maintenance)	3.37E-07
ICCDP (DG in repair)	4.38E-07

Table RAI 8-4
McGuire: Revised Set of Parameters Important to the Analysis

DG fail to start	3.9E-03/d
DG fail to run	2.5E-03/hr
DG mission time	24 hrs
LOSP IE frequency	5.1E-02/yr
DG common cause failure model	MGL
DG fail to start common cause failure probability	1.2E-04/d
DG fail to run common cause failure probability (for the mission run time)	2.4E-03

<u>Required Action, Determine Operable Diesel Generator(s) is not Inoperable due to Common Cause Failure or Perform SR 3 8 1.2 for Operable DG(s)</u>

Table RAI 8-5 provides the revised CDF related results for increasing the CT for the DG CCF evaluation from 24 hours to 72 hours. The ΔCDF and ICCDP values meet the guidelines in Reg Guides 1 174 and 1 177 of 1.0E-06/yr for CDF and 5 0E-07 for ICCDP. Based on this, McGuire is requesting a 72 hour CT for DG CCF evaluations

Table RAI 8-5 McGuire: Revised Results for the DG CCF CT Extension	
Parameter	**Value**
MTTR – for activities greater than 24 hours in duration	37 6 hr
Repair frequency - for activities greater than 24 hours in duration	1 14/yr
CDF Increase	2.19E-08/yr
ICCDP	2 46E-07

Require Action, Restore AC Vital Bus Subsystem to Operable Status

Table RAI 8-6 provides the revised CDF related results for increasing the CT for the AC vital buses from 2 hours to 24 hours. The information in the WCAP regarding the vital AC power system design and the impact of the loss of vital AC on plant operation remains applicable The evaluation assumptions also remain applicable. The ΔCDF and ICCDP values meet the guidelines in Reg Guides 1.174 and 1.177 of 1 0E-06/yr for CDF and 5.0E-07 for ICCDP Based on this, McGuire is requesting a 24 hour CT for AC vital bus inoperability.

Table RAI 8-6 McGuire: Revised Results for the AC Vital Bus CT Extension	
Parameter	**Value**
CDF (2 hr CT)/year	2.177E-05
CDF (24 hr CT)/year	2 179E-05
CDF increase/year	1.990E-08
CCDF (vital bus in repair)/year	3.71E-05
CCDF (vital bus in test or scheduled maintenance)/year	2.89E-05
ICCDP (vital bus in repair)	4.21E-08
ICCDP (vital bus in test or scheduled maintenance)	1.95E-08

Sequoyah: Revised CDF Related Results (DG CCF and AC Vital Bus CT Extensions)

Sequoyah is requesting the DG CCF CT extension and the vital AC bus CT extension

Required Action, Determine Operable Diesel Generator(s) is not Inoperable due to Common Cause Failure or Perform SR 3.8 1.2 for Operable DG(s)

The CDF related results for the DG CCF CT extension are provided on Table 8-5 of WCAP-15622, and both the ΔCDF and the ICCDP values meet RG 1.174 and 1 177 acceptance guidelines Based on this, Sequoyah is requesting a 72 hour CT for DG CCF evaluations

Required Action, Restore AC Vital Bus Subsystem to Operable Status

Table RAI 8-7 provides additional CDF related results for increasing the CT for the AC vital buses from 2 hours to 24 hours. The information in the WCAP regarding the vital AC power system design and the impact of the loss of vital AC on plant operation remains applicable The evaluation assumptions also remain applicable. The ΔCDF and ICCDP values meet the guidelines in Reg. Guides 1.174 and 1.177 of 1 0E-06/yr for CDF and 5.0E-07 for ICCDP Based on this, Sequoyah is requesting a 24 hour CT for AC vital bus inoperabilities

Table RAI 8-7 Sequoyah: Revised Results for the AC Vital Bus CT Extension	
Parameter	**Value**
CDF (2 hr CT)/year	3.77E-05
CDF (24 hr CT)/year	3.77E-05
CDF increase/year	<1E-07/yr
CCDF (vital bus in repair)/year	1 59E-04
CCDF (vital bus in test or scheduled maintenance)/year	Not Applicable (see Note 1)
ICCDP (vital bus in repair)	3 32E-07
ICCDP (vital bus in test or scheduled maintenance)	Not Applicable (see Note 1)

Notes·

1. The CCDF and ICCDP values are not provided for test and scheduled maintenance activities since these components are not taken out of service for test or scheduled maintenance activities.

RAI 9: RG 1 177 states that when multiple TS changes are being considered, the combined impact of the changes should be considered in addition to the individual impacts. Appendix C, Step 7, states that cumulative risk needs to be determined but the results are not discussed in WCAP-15622. Provide a discussion of the combined impact of the proposed changes with respect to WCAP-15622.

Response: These CT extensions are, for the most part, independent of each other. Therefore, to determine the cumulative impact it is only necessary to sum the individual contributions This is shown on Table RAI 9-1 in terms of CDF and in Table RAI 9-2 in terms of LERF for the plants providing updated risk results All increases in CDF and LERF are less than the 1E-06/yr CDF guideline and the 1E-07/yr LERF guideline in Regulatory Guide 1.174.

Table RAI 9-1
Combined Core Damage Frequency Impact of the Individual Technical Specification CT Extensions

Tech Spec. CT Change	Core Damage Frequency Change			
	Callaway (per year)	Comanche Peak (per year)	McGuire (per year)	Sequoyah (per year)
Diesel Generator CT Increase (LCO 3.8.1, Action B.4)	6 76E-07	4.87E-07	2.10E-07	Not Applicable
Diesel Generator Common Cause Failure CT Increase (LCO 3.8 1, Actions B.3 1 and B.3.2)	Not Applicable	Not Applicable	2.19E-08	1 86E-08
Vital AC Bus CT Increase (LCO 3.8 9, Action B.1)	Not Applicable	Not Applicable	1.99E-08	<1E-07
Total	6.76E-07	4 87E-07	2 52E-07	<1.19E-07

Table RAI 9-2
Combined Large Early Release Frequency Impact of the Individual Technical Specification CT Extensions

Tech. Spec CT Change	Large Early Release Frequency Change			
	Callaway (per year)	Comanche Peak (per year)	McGuire (per year)	Sequoyah (per year)
Diesel Generator CT Increase (LCO 3.8.1, Action B.4)	8.25E-10	1.74E-08	5.90E-08	Not Applicable
Diesel Generator Common Cause Failure CT Increase (LCO 3.8 1, Actions B 3.1 and B 3.2)	Not Applicable	Not Applicable	4.64E-09	<1.86E-08[1]
Vital AC Bus CT Increase (LCO 3.8.9, Action B.1)	Not Applicable	Not Applicable	2 87E-08	6 00E-09
Total	8 25E-10	1.74E-08	9 23E-08	<2.46E-08

Notes:
1 The impact on CDF is calculated to be 1.86E-08/yr as reported in WCAP-15622. The LERF impact will be less than this value, but was not calculated since this represents an acceptable LERF impact (less than 1E-07/yr) per Regulatory Guide 1.174.

RAI 10. For alternate AC sources credited in the analysis, confirm that the credited AC source meets the criteria set forth for SBO performance in industry and staff guidance (RG 1.155 and NUMARC 8700)

Response: The detailed response to this RAI will be provided in each licensee's License Amendment Request following the NRC's approval of the changes proposed in WCAP-15622. Each licensee requesting the DG completion time extension proposed in this WCAP that is crediting an alternate AC power source, those currently included in the WCAP and those referencing the WCAP in future LARs, will provide the requested information.

RAI 11. The proposed completion times are requested in part to facilitate on-line maintenance or at-power preventive maintenance. Although the frequency and duration of the completion time may be estimated with the resulting unavailability calculated, discuss the effects that additional testing at power might have on plant risk due to improper maintenance or additional testing required that would have previously been performed during shutdown and not directly related to the extended completion time itself. Studies have shown that restoration failures have the potential to initiate a second loss of power that is difficult to diagnose and recover when that restoration was not always performed in accordance with established procedures.

Response: The CT increase for the diesel generators is the proposed change that will be primarily used by the utilities for performing preventive maintenance activities during power operation The other CT extensions proposed will be primarily used to provide additional time to perform troubleshooting and component repair during power operation

As stated in the Bases for Technical Specification 3 8 (Electrical Power Systems) of NUREG-1431, Rev. 2, the AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The surveillance requirements for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1 9, Regulatory Guide 1.108, and Regulatory Guide 1 137, as addressed in the FSAR.

The issues in this RAI are related to the availability of the DG following additional at-power preventive maintenance activities and also the potential for inducing electrical system transients during the preventive maintenance activities or during the post maintenance testing. As stated in the previous paragraph, surveillance requirements on the AC sources are designed in accordance with the noted Regulatory Guides to ensure OPERABILITY of the DGs These issues are addressed as follows:

- After maintenance activities, components/systems are subject to post maintenance testing and system alignment verification Both are directed at demonstrating that the system is operable and will perform as required if demanded These tests are performed regardless of the mode in which the testing is completed Following the DG at-power maintenance activity, a test will be completed to demonstrate operability of the DG This test is typically the monthly DG test required in plant Technical Specifications. This monthly test is designed to be performed with the plant at-power and demonstrates DG operability.

- DG maintenance activities are completed with the DG disconnected from the plant electrical distribution system This configuration inhibits electrical transients from being introduced into the plant's electrical system

- The testing is typically completed in a configuration that will not induce electrical system transients The test used to demonstrate DG operability is the same as that used to meet the Technical Specification monthly test requirement This test is designed to be performed at-power and not introduce electrical system transients that could impact plant operation

The licensees requesting this change will confirm the above in their LAR submittals. Information to be provided by each licensee includes:

- The test that will be used following at-power maintenance activities to demonstrate DG operability

- Confirmation that the DG is disconnected from the plant's electrical system during at-power preventive maintenance activities

- The precautions taken to ensure that plant electrical distribution system transients that could impact plant operation do not occur during the maintenance activity or follow-on testing.

RAI 12. WCAP-15622 discusses the risk impact of moving diesel maintenance activities from shutdown to at-power operation. WCAP-15622 found that performing scheduled maintenance activities at-power results in ICCDPs significantly smaller than for shutdown The conclusion presented by WCAP-15622 were based on the analysis for one plant and were expected to be applicable for all plants that schedule EDG maintenance at the beginning of the outage It is not clear that a neutral or net risk impact improvement will result from the proposed shift to on-line EDG maintenance While a qualitative argument could be made with regard to performing maintenance on-line as opposed to shutdown, it is not clear that a quantitative argument applicable to all plants would be bounding Previous studies (NUREG/CR-5994) have indicated that with respect to CDF, taking an EDG out-of-service for maintenance during the early stages of an outage is comparable to short interval maintenance performed during power operation. However, the likelihood of core damage can be reduced substantially by scheduling long duration maintenance during refueling when decay heat is low as opposed to power operation. The staff also notes that the standard TSs do not differentiate when work may be performed (what plant state) and therefore any risk averted by performing maintenance during power operation is problematic Provide a discussion as to the generic applicability of WCAP-15622 results including plants without low power shutdown risk models

Response: Numerous scheduling schemes can be developed for completing DG maintenance during an outage. Section 8.2 6 of the WCAP provides one scheme used by Comanche Peak This involves removing the DG from service in Mode 5. The purpose of providing this information is to demonstrate that these activities are not risk free Section 8.2 6 also discusses, on a qualitative basis, the possible risk of doing these activities while shutdown As discussed, if DG maintenance activities are completed in Mode 6, then the primary issue is loss of decay heat removal following a loss of offsite power event. Decay heat removal is important and can only be provided by the residual heat removal system that requires AC power for operation AC power will be available, but degraded when one DG is out of service

The placement of DG maintenance in the outage schedule is dependent on several elements including other activities that are planned for the outage and the planned outage length DG maintenance activities can become critical path items to an outage To eliminate this as a critical path element, it may be necessary to initiate the activities in Mode 5, which, as noted above, is in compliance with the Technical Specifications

The risk results provided in Section 8.2 6 are applicable to other plants that also begin DG outages in Mode 5. The absolute values of the ICCDPs provided will vary depending on the plant, but in general, plant specific results would also show similar results, that is, a non negligible risk But these plants may also defer removing DGs from service until later in the outage when the risk level is lower.

The point is, the risk of doing DG maintenance in the outage is not risk free and needs to be considered, at least qualitatively, in the decision process. The level of risk will change from outage-to-outage and also from plant-to-plant, depending on the utility's outage approach. But, the exact value is not crucial As demonstrated in the WCAP and in responses to RAIs #8 and #16, the impact of the CT increase on risk (CDF, LERF, ICCDP, and ICLERP) meets the guidelines provided in Regulatory Guides 1 174 and 1.177, therefore, the argument for the acceptability of this change is based on the low impact of this change on at-power plant risk, not the tradeoff with shutdown risk.

RAI 13. The TR does not discuss whether each EDG at a plant is equivalent from a risk perspective when taken out of service Discuss any differences and the impact on the TR conclusions. Additionally, discuss whether combining plant reliability data that may obscure the performance of individual EDGs at multi-unit sites

Response: The following discusses the equivalence of the diesel generators at each of the four plants responding to these RAIs and the reliability of the individual EDGs Information provided includes RAW values for each DG, DG reliability history, list of loads on each DG, and a concluding statement of why the results are applicable to both (all) DGs.

CALLAWAY

1. RAW values for each DG

The RAW values for the DG test/maintenance basic events are:

NE01 (DG1) 4.81
NE02 (DG2) 3.89

The CT extension risk calculations were performed using the DG NE01 TM basic event, which exhibits the higher RAW value.

2. Reliability information for each DG

Callaway has incurred the following DG failures over the five year period from 1/1/96 to 12/31/00.

NE01. One (1) failure to start over 94 start demands (Corresponding failure rate is 1.06E-02 per demand) No failures to run

NE02: One (1) failure to run over 158 7 hours of run time. (Corresponding failure rate is 6 3E-03 per hour.) No failures to start

3. List of loads on each DG

The loads on each DG provided in the FSAR (Figure 8.3-2, Callaway Plant, List of Loads Supplied by the Emergency Diesel Generator) were reviewed. From this review it was concluded that the loads on the DGs are essentially symmetrical Some of the loads on each DG that are important in the Callaway PRA are provided in the following table.

Table RAI 13-1 Key Diesel Generator Loads for Callaway		
System/Train/Component	DG NE01	DG NE02
Component Coolıng Water Pump	A, C	B, D
Containment Spray Pump	A	B
Residual Heat Removal Pump	A	B
Essentıal Service Water Pump	A	B
Centrifugal Charging Pump	A	B
MD Auxiliary Feedwater Pump	A	B
Ultimate Heat Sink Coolıng Tower Fans	A, C	B, D
Battery Chargers	NK21, 23, 25	NK22, 24, 26
Contaınment Coolers	A, C	B, D
Class 1E Equipment A/C	A	B
Fuel Oil Transfer Pump	A	B

4 Dıscussion on Applıcability of Results to Both DGs

The Callaway risk calculatıon results supporting the DG CT extension are applicable to both DGs for the following reasons:

- DG NE01 was the basis for the calculations and the results provided. This DG has the higher RAW value of the two in the Callaway PRA model as noted above. Therefore, the values for the risk metrics calculated usıng DG NE01 will bound the corresponding values for DG NE02
- The loads on the DGs are essentıally symmetrical.
- Callaway specific data shows that both DGs have exhibited similar relıabilıty performance, as noted above, wıth respect to faılures to start and failures to run

COMANCHE PEAK

The impact of the CT extensıon was evaluated for each DG separately and the rısk metrics reported for each DG This information (risk metrics) is provided in the response to RAI 8 for CDF and in the response to RAI 16 for LERF. Table RAI 8-2 provıdes the ICCDPs for DG A out of service and for DG B out of service and Table RAI 16-1 provıdes the ICLERPs for DG A out of servıce and for DG B out of service. The values are nearly identical demonstratıng that DGs are equivalent.

1 RAW values for each DG

Not provided since the risk metrics are provided for each DG that demonstrate they are equıvalent (see Tables RAI 8-2 and RAI 16-1).

2. Reliability information for each DG

The following table provıdes the diesel generator relıability information for Comanche Peak

Comanche Peak Diesel Generator Reliability Information			
Diesel Generator	**Failure Mode**	**Failures**	**Demand or Hours**
Unit 1, DG A	Fail to Start	0	50 demands
	Fail to Run	1	151 hours
Unit 1, DG B	Fail to Start	1	47 demands
	Fail to Run	1	117 hours
Unit 2, DG A	Fail to Start	0	45 demands
	Fail to Run	0	105 hours
Unit 2, DG B	Fail to Start	0	45 demands
	Fail to Run	0	105 hours

3 List of loads on each DG

The loads on each DG were reviewed Some of the loads on each DG that are important in the Comanche Peak PRA are provided in Table RAI 13-2. From this review it was concluded that the loads on the DGs are essentially symmetrical

Table RAI 13-2 Key Diesel Generator Loads for Comanche Peak				
System/Train/Component	**DG 1-1**	**DG 1-2**	**DG 2-1**	**DG 2-2**
Station Service Water Pump	1-01	1-02	2-01	2-02
Auxiliary Feedwater Pump	1-01	1-02	2-01	2-02
Centrifugal Charging Pump	1-01	1-02	2-01	2-02
Safety Injection Pump	1-01	1-02	2-01	2-02
Residual Heat Removal Pump	1-02	1-02	2-01	2-02
Containment Spray Pump	1-01, 1-03	1-02, 1-04	2-01, 2-03	2-02, 2-04
Component Cooling Water Pump	1-01	1-02	2-01	2-02
UPS and Distribution Room A/C Unit	1-01	1-02	2-01	2-02
DG Fuel Oil Transfer Pump	1-01, 1-02	1-03, 1-04	2-01, 2-02	2-03, 2-04
Battery Charger	1-01, 1-03, 1-05, 1-07	1-02, 1-04, 1-06, 1-08	2-01, 2-03, 2-05, 2-07	2-02, 2-04, 2-06, 2-08

4. Discussion on Applicability of Results to Both DGs

The Comanche Peak risk calculation results supporting the DG CT extension are provided for each DG The CT analysis results are applicable to both DGs for the following reasons

- The risk metrics for each DG are provided, and the CCDF and ICCDP values are nearly the same for each DG.
- The loads on the DGs are essentially symmetrical
- Comanche Peak specific data shows that all DGs have exhibited similar reliability performance, as noted above, with respect to failures to start and failures to run.

McGUIRE

1. RAW values for each DG

The RAW values based on the DG fail-to-run basic events are.
DG1A: 1 90
DG1B· 1 86

The slight difference is due to the PRA modeling which has train A systems in service and train B systems in standby. The support system (service water) for DG1A is in service while the service water for DG1B is in standby with test and maintenance unavailability included There is no test or maintenance unavailability for the running trains.

2. Reliability information for each DG

The DG unavailability data for McGuire is provided on the following table:

Hours of Unavailability (while at Modes 1-3)			
Diesel Generator	**1/1/1996 - 12/31/97**	**1/1/1998 - 6/30/1999**	**7/1/1999 – 12/31/2000**
1A	177.8	118 3	137.2
1B	132.0	94 2	93.9
2A	63.8	663 1	108.5
2B	145.4	155 9	168.4

Note that DG 2A includes an unavailability of approximately 506 hours due to a failure of a diesel generator cylinder exhaust valve seat in late 1998. This is reflected in the unavailable hours for the timeframe from 1/1/1998 to 6/30/1999. Without these hours, the unavailability for DG 2A would be similar to the other DGs. This one time failure is not considered to be indicative of a poor performing DG

3. List of loads on each DG

There are no plant design differences or asymmetries that would make any one diesel generator more important than another at McGuire. Some of the loads on each DG that are important in the McGuire PRA are provided in the following table.

Table RAI 13-3 Key Diesel Generator Loads for McGuire				
System/Train/Component	**DG-1A**	**DG-1B**	**DG-2A**	**DG-2B**
Nuclear Service Water Pump	1A	1B	2A	2B
Auxiliary Feedwater Pump	1A	1B	2A	2B
Centrifugal Charging Pump	1A	1B	2A	2B
Safety Injection Pump	1A	1B	2A	2B
Residual Heat Removal Pump	1A	1B	2A	2B
Containment Spray Pump	1A	1B	2A	2B
Component Cooling Water Pump	1A1,1A2	1B1,1B2	2A1,2A2	2B1,2B2
Vital AC System Battery Charger	EVCA & EVCC	EVCB& EVCD	EVCA & EVCC	EVCB& EVCD
Containment Air Return Fan	1A	1B	2A	2B

4 Discussion on Applicability of Results to Both DGs

The McGuire risk calculation results supporting the DG CT extension are applicable to both DGs for the following reasons

- The RAW values for DG1A and DG1B are essentially the same, indicating both are equally important.
- The loads on the DGs are essentially symmetrical.
- McGuire specific data shows that both DGs have exhibited similar reliability performance, as noted above, with respect to component unavailability.

SEQUOYAH

1 RAW values for each DG

The RAW values for the DG test/maintenance basic events are:

DG 1A-A: 1.70
DG 1B-B 1 67

2 Reliability information for each DG

The following failures have occurred on the DGs at Sequoyah from January 1997 to January 2002.

Date	Diesel Generator	Mode of Failure	Comments
Nov-01	2A-A	Start	Air start motor pneumatic delay
Dec-99	2A-A	Run	Lube oil loss through broken sightglass
Aug-99	2A-A	Run	CO2 damper link failed (room ventilation)
Jul-97	2A-A	Run	Stator failure following repair
Feb-97	2A-A	Run	Governor/actuator failure

All of these failures occurred on diesel generator 2A-A The cause of the failure for each occurrence does not indicate a recurrent failure mode These failures have not occurred on the other DGs, therefore, common cause failure modes are not an issue. Since Sequoyah is requesting an extension to 72 hours for the CT for the CCF evaluation, this is an important point.

Since all failures occurred on the DG 2A-A, the reliability of the limiting diesel is:

1.1% failure to start (2 in 187 attempts)
3 2% failure to run (4 in 124 tests)
4 3% Total failure rate from data

Note that the failure to start value is based on two failures, but only one is listed in the above table The second failure to start event occurred outside the timeframe listed

This failure rate is less than the 5 0% value used for the 1A-A DG in the PSA evaluation included in the WCAP.

3 List of loads on each DG

The loads on each DG was reviewed and are provided in Table RAI 13-4. From this it was concluded that the loads on the DGs are essentially symmetrical Some of the loads on each DG that are important in the Sequoyah PRA are provided in the following table.

Table RAI 13-4
Key Diesel Generator Loads for Sequoyah

System/Train/Component	DG-1A	DG-1B	DG-2A	DG-2B
Centrifugal Charging Pumps	1A	1B	2A	2B
Safety Injection Pumps	1A	1B	2A	2B
Residual Heat Removal Pumps	1A	1B	2A	2B
Auxiliary Feedwater Pumps	1A	1B	2A	2B
Essential Control Air			0A[1]	0B[1]
Station Air Compressors	0A[1]	0B[1]		
Component Cooling Water Pumps	1A, 0B	1A	2A	2A, 0B
Essential Raw Cooling Water Pumps	0A[1]	0B[1]	0A[1]	0B[1]
Containment Spray Pumps	1A	1B	2A	2B
Containment Air Return Fan	1A	1B	2A	2B
480V Transformer/Board Room Cooling	1A	1B	2A	2B

Note:
1 – A "0" indicates that the equipment is shared between the two units

4 Discussion on Applicability of Results to Both DGs

The Sequoyah risk calculation results supporting the DG CT extension are applicable to all DGs for the following reasons

- The RAW values for DG1A and DG1B are essentially the same, indicating both are equally important.
- The loads on the DGs are essentially symmetrical
- Sequoyah specific data shows that all DGs have exhibited similar reliability performance, as noted above, with respect to component unavailability except for DG 2A-A. There have been several failures on this DG, but not a recurring failure mode This information has been included in the evaluation supporting this CT increase.

RAI 14. Will the proposed allowed outage times (AOTs) for EDGs/Vital 120 VAC power remain consistent with maintenance rule reliability goals or commitments for SBO?

Response: Paragraph (a)(1) of the Maintenance Rule requires licensees to set goals and to monitor the performance or condition of SSCs to ensure the SSCs are capable of performing their intended functions. The goals must be commensurate with safety and requires operators to take appropriate corrective action when the performance or condition of an SSC does not meet established goals Paragraph (a)(3) requires that these performance and condition monitoring activities, and associated goals and preventive maintenance activities, be evaluated on a periodic basis. This requires licensees to systematically review activities under (a)(1) of the rule and to adjust those activities where needed In addition, it is also required that adjustments be made, as necessary, to ensure that the objective of preventing failures of SSCs through maintenance is appropriately balanced against the objective of minimizing the time SSCs are unavailable because of monitoring or preventive maintenance activities.

The current DG and vital AC power Maintenance Rule performance criteria/goals are independent of the requested CT extensions in this WCAP. If the extended CTs are shown to impact the performance criteria/goals, such as taking longer to complete repairs or doing additional preventive maintenance activities at-power, then these will be adjusted appropriately via paragraph (a)(3).

With regard to DG commitment for SBO, Regulatory Guide 1.155 defines an approach for complying with the regulation that requires nuclear power plants to be capable of coping with a station blackout for a specified duration The application of this approach results in selecting a minimum acceptable station blackout duration capability from 2 to 16 hours, depending on a comparison of the plant's characteristics with those factors that have been identified as significantly affecting the risk from station blackout. These factors include redundancy of the onsite emergency AC power system, the reliability of the onsite emergency AC power sources (e.g., diesel generators), the frequency of loss of offsite power, and the probable time to restore offsite power. The CT extensions requested in this WCAP do not impact any of these factors, therefore, the proposed changes will remain consistent with the SBO commitments.

RAI 15. Provide a discussion on the configuration risk management program implementation to avoid risk significant configurations during extended EDG and vital 120 VAC power maintenance, repair, or overhaul

Response: Paragraph (a)(4) of the Maintenance Rule (10 CFR 50 65) requires that before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance) the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities Licensees have developed configuration risk management programs for their plants based on their plant specific PRA models to meet this requirement. Therefore, the configuration risk management program developed to satisfy the Maintenance Rule requirement will be used to evaluate the plant risk associated with diesel generator outages and vital 120 VAC power outages

For the plants that request the CT extension for performing preventive activities at-power and that credit reduced switchyard activities and/or weather related restrictions in the risk analysis, conditions will be added to the configuration risk management program to ensure consistency with the analysis assumptions These conditions may include restraints on entering the extended CT when switchyard activities are in progress or when severe weather is forecast.

RAI 16. Large early release frequency (LERF) or incremental conditional large early release probability (ICLERP) is not presented in WCAP-15622. Please provide results and a discussion

Response: Tables RAI 16-1, RAI 16-2, and RAI 16-3 provide the LERF and ICLERP values for Callaway, Comanche Peak, McGuire, and Sequoyah for the CT increases of interest The following discusses these results.

Required Action, Restore (required) Diesel Generator to Operable Status

Table RAI 16-1 provides the large early release related parameter results for extending the DG CT for Callaway, Comanche Peak, and McGuire

Callaway LERF Related Results· DG CT Extension

The Callaway results show that the impact on LERF for extending the DG CT to 11 days for only scheduled activities meets the acceptance guideline in Regulatory Guide 1.174 (small impact on LERF is less than 1E-07/yr) and that the ICLERP for scheduled activities meets the acceptance guideline in Regulatory Guide 1.177 (less than 5E-08) In addition, the internal event LERF is less than the 1E-05/yr threshold for limiting plant changes that result in small increases in LERF. As previously discussed, restrictions on activities that could impact the reliability of the switchyard and access to the switchyard while a DG is out of service will be implemented, and DG outage activities will be planned during periods when the grid reliability is high These restrictions have been accounted for in the calculations providing the LERF impact and ICLERP values

Comanche Peak LERF Related Results DG CT Extension

The Comanche Peak results show that the impact on LERF for extending the DG CT to 7 days for scheduled and repair activities meets the acceptance guideline in Regulatory Guide 1.174 (small impact on LERF is less than 1E-07/yr) and that the ICLERP for scheduled and repair activities meets the acceptance guideline in Regulatory Guide 1.177 (less than 5E-08) These values are provided for DG A and DG B out of service In addition, the internal event LERF is less than the 1E-05/yr threshold for limiting plant changes that result in small increases in LERF. As previously discussed, restrictions on activities that could impact the reliability of the switchyard while a DG is out of service will be implemented and DG outage activities will not be planned when severe weather is forecast These restrictions have been accounted for in the calculations providing the LERF impact and ICLERP values

McGuire LERF Related Results: DG CT Extension

The McGuire results show that the impact on LERF for extending the DG CT to 7 days for scheduled and repair activities meets the acceptance guideline in Regulatory Guide 1.174 (small impact on LERF is less than 1E-07/yr) and that the ICLERP values for scheduled and repair activities are slightly above the acceptance guideline in Regulatory Guide 1 177 (less than 5E-08) Note that the 5E-08 value is a guideline and not a hard criterion that must be met In addition, the internal event LERF is less than the 1E-05/yr threshold for limiting plant changes that result in small increases in LERF. As previously discussed, this analysis does not credit any restrictions on activities that could impact the reliability of the switchyard and access to the switchyard while a DG is out of service, and does not credit limiting DG outage activities to certain times of the year.

With regard to this LERF assessment, the McGuire LERF model is a simplified and conservative approach based on NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events " The major contributor to the LERF is interfacing system LOCAs. The sequences associated with DG failures (or vital bus failures) do not contribute significantly to this plant damage state Station blackout sequences do have the potential to lead to early containment failure as a result of hydrogen combustion because the igniters are not available The simplified LERF model used assumes that all the early containment failures contribute to LERF. This is a conservative assumption and leads to a higher than expected LERF and inflates the ICLERP values.

The most recent revision to the McGuire full scope Level 3 PRA determined that the early containment failure release categories did not contribute significantly to the early fatality risk since the warning time was adequate for effective evacuation for the dominant sequences. Therefore, the actual LERF impact estimated by the simplified approach is judged to be conservative with respect to a more sophisticated approach which evaluates LERF as a function of the early fatality risk. This conservatism supports the proposed CT extension In addition, resolution of Generic Safety Issue (GSI), GSI-189, "Susceptibility of Ice-Condenser and Mark III Containments to Early Failure from Hydrogen Combustion During a Severe Accident," may lead to plant modifications regarding backup power to the hydrogen igniters for Station Blackout (SBO) events It is expected that such a resolution of GSI-189 will have a direct impact (improvement) on the LERF. Therefore, it is concluded that the impact of the CT change on risk is acceptable.

Required Action, Determine Operable Diesel Generator(s) is not Inoperable due to Common Cause Failure or Perform SR 3.8.1.2 for Operable DG(s)

Table RAI 16-2 provides the large early release related parameter results for extending the DG CCF evaluation CT for McGuire and Sequoyah

McGuire LERF Related Results DG CCF Evaluation CT Extension

The McGuire results show that the impact on LERF for extending the DG CCF evaluation CT to 72 hours meets the acceptance guideline in Regulatory Guide 1.174 (small impact on LERF is less than 1E-07/yr) and that the ICLERP criterion in Regulatory Guide 1 177 (less than 5E-08) is essentially met In addition, the internal event LERF is less than the 1E-05/yr threshold for limiting plant changes that result in small increases in LERF.

Sequoyah LERF Related Results: DG CCF Evaluation CT Extension

The Sequoyah results show that the impact on LERF for extending the DG CCF evaluation CT to 72 hours meets the acceptance guideline in Regulatory Guide 1.174 (small impact on LERF is less than 1E-07/yr) and that the ICLERP criterion in Regulatory Guide 1.177 (less than 5E-08) is also met. In addition, the internal event LERF is less than the 1E-05/yr threshold for limiting plant changes that result in small increases in LERF.

Required Action, Restore AC Vital Bus Subsystem to Operable Status

Table RAI 16-3 provides the large early release related parameter results for extending the AC vital bus CT for McGuire and Sequoyah

McGuire LERF Related Results: AC Vital Bus CT Extension

The McGuire results show that the impact on LERF for extending the AC vital bus CT to 24 hours meets the acceptance guideline in Regulatory Guide 1 174 (small impact on LERF is less than 1E-07/yr) and that the ICLERP criterion in Regulatory Guide 1.177 (less than 5E-08) is also met. In addition, the internal event LERF is less than the 1E-05/yr threshold for limiting plant changes that result in small increases in LERF.

Sequoyah LERF Related Results   AC Vital Bus CT Extension

The Sequoyah results show that the impact on LERF for extending the AC vital bus CT to 24 hours meets the acceptance guideline in Regulatory Guide 1.174 (small impact on LERF is less than 1E-07/yr) and that the ICLERP criterion in Regulatory Guide 1.177 (less than 5E-08) is also met   In addition, the internal event LERF is less than the 1E-05/yr threshold for limiting plant changes that result in small increases in LERF

Table RAI 16-1 Impact of Diesel Generator Completion Time Increase on Large Early Release Related Parameters				
Parameter	**Plant and Completion Time**			
	Callaway[1]		**Comanche Peak**[2]	**McGuire**[3]
	7 days	**11 days**	**7 days**	**7 days**
LERF (72 hr CT) (per yr)	4.202E-07	4.202E-07	5.44E-07	2.15E-06
LERF (extended CT) (per yr)	4 207E-07	4.210E-07	5.64E-07	2.21E-06
LERF Increase (per yr)	5.25E-10	8.25E-10	1.74E-08	5.90E-08
CLERF (DG in test or scheduled maintenance) (per yr)	4.36E-07	4.36E-07	1.45E-06 (Trn A) 1.44E-06 (Trn B)	5.63E-06
CLERF (DG in repair) (per yr)	Not Applicable	Not Applicable	1.61E-06 (Trn A) 1.61E-06 (Trn B)	8 25E-06
ICLERP (DG in test or scheduled maintenance)	3.72E-10	5.84E-10	1.74E-08 (Trn A) 1.72E-08 (Trn B)	6.67E-08
ICLERP (DG in repair)	Not Applicable	Not Applicable	2.04E-08 (Trn A) 2.04E-08 (Trn B)	8 83E-08

Notes:

1. As discussed previously, Callaway is requesting the CT extension only for scheduled activities and plans on implementing restrictions on activities that could impact the reliability of the switchyard and access to the switchyard while a DG is out of service, and will plan DG outage activities during a period when the grid reliability is high. These restrictions have been accounted for in the calculations to determine the large early release parameters provided above.
2. As discussed previously, Comanche Peak is requesting the CT extension for both scheduled and repair activities, and plans on implementing restrictions on concurrent test and maintenance activities in the switchyard that could impact the reliability of the switchyard, and will plan DG outage activities when no severe weather is forecast. These restrictions have been accounted for in the calculations to determine the large early release parameters provided above.
3. The analysis and results provided above for McGuire do not credit any restrictions on concurrent activities or restrict DG maintenance activities to certain times of the year.

Table RAI 16-2 Impact of Diesel Generator CCF Evaluation Completion Time Increase to 72 Hours on Large Early Release Related Parameters		
Parameters	Plant	
	McGuire	Sequoyah
LERF (current CT) (per yr)	2.15E-06	6 18E-07
LERF Increase (per yr)	4.64E-09	<1 86E-08[1]
ICLERP (one DG out of service for repair)	5 01E-08	9 86E-09

Notes:
1. The impact on CDF is calculated to be 1 86E-08/yr as reported in WCAP-15622. The LERF impact will be less than this value, but was not calculated since this represents an acceptable LERF impact (less than 1E-07/yr) per Regulatory Guide 1.174.

Table RAI 16-3 Impact of AC Vital Bus Completion Time Increase to 24 Hours on Large Early Release Related Parameters		
Parameters	Plant	
	McGuire	Sequoyah
LERF (2 hr CT) (per yr)	2 15E-06	6 18E-07
LERF (24 CT) (per yr)	2.18E-06	6 24E-07
LERF Increase (per yr)	2.87E-08	6.00E-09
CLERF (vital bus in test or scheduled maintenance) (per yr)	4.69E-06	Not Applicable (see Note 1)
CLERF (vital bus in repair) (per yr)	1 27E-05	7 59E-06
ICLERP (vital bus in test or scheduled maintenance)	6 96E-09	Not Applicable (see Note 1)
ICLERP (vital bus in repair)	2.89E-08	2.08E-08

Notes:
1. The CLERF and ICLERP values are not provided for test or schedule activities since these components are not taken out of service for scheduled or routine maintenance activities

RAI 17. Discuss considerations to prohibit entry or termination of an extended AOTs (maintenance) should external event conditions or warnings exist.

Response: Only the DG CT extension will be used primarily to perform additional preventive maintenance activities when the plant is at-power. This type of activity is planned in advance and licensees can take precautions to reduce the probability of a loss of offsite power event from occurring when operating with a DG unavailable due to maintenance. External event conditions that are important with regard to loss of offsite power events are conditions that can impact the availability of offsite power to the plant. Of specific interest in this study is severe weather conditions.

To address this, utilities implementing the DG CT extension and crediting a reduced LOSP initiating event frequency, due to weather related restrictions, will develop a procedure or include restrictions in appropriate procedures or in their configuration risk management program as part of Maintenance Rule implementation (if such restrictions do not already exist) to prohibit entry into the CT for preventive maintenance activities if severe weather is forecast. In addition, if DG preventive maintenance is ongoing and severe weather is forecast, the procedures will require the DG to be restored to service as soon as possible. Affected licensees will develop and implement a procedure or appropriate guideline, if not already addressed by the Maintenance Rule, to meet this restriction In addition, the severe weather restriction will also be included in the list of Tier 2 restrictions identified by the licensees

RAI 18. For EDG maintenance that is not performed every cycle (five year EDG overhaul), the EDG overhaul completion time is averaged over a five year period The TR states that actual (proposed) completion times (CTs), ICCDP and realistic CTs for CDF are used. Provide an evaluation of the risk impact for EDG overhauls on ICCDP/CDF using the CTs including the EDG five year maintenance

Response: PRA models use mean or average values for component unavailability due to test and maintenance activities In some years it is expected that the actual unavailability due to test or maintenance activities will be lower than this mean value and in some years it will be higher PRA models do not attempt to vary the test and maintenance unavailability values from year-to-year to capture this variability Instead, the mean value over a defined period is used so as not to overstate or understate the importance of test and maintenance activities

The approach used to evaluate the impact of the DG CT extension on risk is consistent with Reg. Guides 1 174 and 1 177 The results presented in the WCAP already have factored the 5 year DG maintenance outage time into the maintenance unavailability contributions. Regulatory Guide 1 174 does not require the maximum possible system or component unavailability values to be used in the risk analysis, but that a mean value be used. Therefore, the 5 year DG outage is factored into the maintenance outage time as an event that occurs once every five years Reg Guide 1 177 requires the calculation of ICCDP and ICLERP based on the full CT being used for a maintenance or test activity. This value places a limit on the length of the CT based on the acceptance criteria provided in Reg Guide 1.177 Therefore, the ICCDP is already provided (based on the extended CT of 7 days or 11 days, depending on the plant) and the ΔCDF including the 5 year maintenance outage time is also included in the ΔCDF calculation

It should be noted that a ΔCDF calculation based solely on the fifth year activities has not been provided since it is not required by the Reg Guides. If it was calculated, it is not clear how such information would be used in the decisionmaking process In any one year, the assumed test or maintenance unavailability for a component can exceed the value assumed in the PRA model, because for another year it will be less than the PRA value, averaging out over a period of time to the mean value. Limitations on single event unavailabilities are based on the ICCDP and ICLERP calculations

In addition, the CRMP (Maintenance Rule, (a)(4)) limits the time allowed in any specific configuration based on the risk level The Maintenance Rule also requires development of performance criteria and, if necessary, performance goals The component performance is evaluated with respect to these criteria and actions taken to meet the goals if the performance criteria are not met. Finally, performance indicators for the DG unavailability will also limit the amount of work that can be done. Therefore, there are sufficient controls in place to maintain an acceptable DG availability during cycles with potentially longer outage time due to infrequent overhauls.

Based on this, it is concluded that a risk evaluation based on fifth year maintenance activities is not required by the Reg. Guides, although the ICCDPs are provided. It is also concluded that there are controls in place via the Maintenance Rule to limit EDG unavailability to ensure performance criteria are met

RAI 19. Section 7.1 of WCAP-15622 states that the proposed completion times primarily affect the CDF and have only a secondary effect on containment integrity such that as the CDF increases, the LERF will increase by a similar amount. In other words, if the CDF increases by a set amount, the LERF will also increase by the same amount. Please explain

Response: Instead of providing the ΔLERF and ICLERP values in the WCAP, this statement was provided to give an indication of the expected impact of the CT extensions on the LERF metrics The systems of interest in this WCAP impact CDF and LERF, with the primary impact on CDF. The LERF impact is expected to roughly follow the CDF impact since the systems of interest are not primarily used for (large early) release mitigation. Since the response to RAI 16 provides the LERF metrics, further discussion of this statement is no longer necessary

Responses to NRC Request for Additional Information

NRC Letter, D. Holland to G. Bischoff, "Westinghouse Topical Report, WCAP-15622, Rev 0, 'Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times'," January 15, 2002

EP RAI 1. Section 5.1 of WCAP-15622 [i e , the Improved Standard Technical Specifications (ISTS)] conveys that [given a system design that meets design basis requirements defined below] a three-day completion time (CT) for an inoperable ac onsite electric power source takes into account (a) the capacity and capability of the remaining ac sources (i.e , the CT is so short that the probability for failure of engineering safety features (ESF) systems and the remaining operable electric power sources during the CT is considered commensurate with the probability for failure of ESF systems and electric power sources when they are operable and not subject to a CT), (b) the low probability of a design basis accident (DBA) occurring during the CT, and (c) a reasonable time for repairs. Design basis requirements include:

i. ESF systems are operable,
ii. ac electric power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, reactor coolant system, and containment design limits are not exceeded,
iii at least one train of safety systems will remain operable in the event of (a) an assumed loss of all offsite power and a worst case single failure, and (b) an assumed loss of all onsite ac power and a worst case single failure.

If the 3-day CT is increased to a 7-day, 14-day, or longer CT, describe programs and activities and identify existing Final Safety Analysis Report (FSAR) commitments (or proposed new FSAR or technical specifications (TS) commitments) which are (or will be) credited to ensure that the increased CT does not impact design basis requirements. Explain how, with an increased CT, the limiting condition for operation (LCO) will remain so short that the probability for failure of operable ESF systems and the remaining operable electric power sources during the LCO can be considered commensurate with the probability for failure of operable ESF systems and electric power sources when all electric power sources are operable.

Response: This change does not impact the ability of the electrical system to mitigate design basis events. Given that a design basis event has occurred, the plant will have the same capability to mitigate the event before and after this change, and will continue to respond to design basis events in the same manner. As discussed in Sections 7.1 and 7 2 of WCAP-15622, defense-in-depth and safety margins will not be impacted by this change. Therefore, there are no new FSAR or Technical Specification commitments credited to ensure that the increased CT does not impact design basis requirements As discussed in the response to PRA RAI #8, two of the utilities plan on adding commitments to restrict switchyard activities when a DG is out of service for preventive maintenance activities and to restrict when a DG can be voluntarily removed from service for preventive maintenance activities to periods when grid reliability is high. These two utilities credited such restrictions in their analyses to demonstrate the impact on risk is small. These restrictions are to ensure that the risk impact of the change is small, consistent with the plant analyses, and are not related to maintaining the design basis requirements. Another utility did not credit such restrictions, but does credit an alternate AC power source. The availability of this power source is not impacted by this CT extension

What will be impacted by this CT increase is the availability of the diesel generators (onsite AC power source). With the extended CT, the unavailability of the diesel generators is expected to increase slightly. Regulatory Guide 1.174 ("An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis") and Regulatory Guide 1.177 ("An Approach for Plant-Specific, Risk-Informed Decisionmaking Technical Specifications") provide the approach and acceptance guidelines for determining an acceptable change to the plant's licensing basis using a risk-informed approach In this case, the licensing basis change is the increase to the Technical Specification CT for the diesel generator Extending the diesel generator CT will increase the time the DGs are unavailable during power operation by a small amount, which in turn impacts the ability of the plant to respond to loss of offsite power events Using the risk-informed approach, this impact is measured by plant risk via core damage frequency and large early release frequency   Even though the DG unavailabilıty may ıncrease slightly, it should also be noted that there are other controls on the DG unavailability set by the Maintenance Rule and plant performance ındicators

WCAP-15622 and the supplemental analyses discussed ın response to PRA RAI-8 and PRA RAI-16 presented the risk analysis results   Sınce the impact on risk meets the guidelines ın Regulatory Guide 1.174 and 1.177, the proposed change is considered acceptable from the risk perspective   Sınce defense-in-depth and safety margıns are not impacted by this change, the CT increase is acceptable from the deterministıc perspectıve. Therefore, the CT will remain short enough such that the probabılıty of failure of operable ESF systems and the remaınıng operable electrıc power sources while in the LCO can be considered commensurate with the probability of failure of operable ESF systems and electric power sources when all electrıc power sources are operable.

EP RAI 2. Explain how (and to what extent) the risk arguments presented in the WCAP can be related to the probability for failure of operable ESF systems and remaining operable power sources during the LCO as compared to the probability for failure of operable ESF systems and electric power sources when all electric power sources are operable.

Response: The probability of failure of the operable ESF systems and electric power sources during the LCO and the probability of failure of the operable ESF systems and electric power sources when all electric power sources are operable is not directly calculated using the risk-informed approach described in Regulatory Guides 1 174 and 1.177, nor is it required. But a measure of this can be obtained indirectly from the risk-informed approach. The baseline core damage frequency (CDF) can be used to represent the probability of failure of the operable ESF systems and electric power sources when all electric power sources are operable This will overstate the probability of failure since this CDF value will include annual system unavailabilities due to test and maintenance activities The conditional CDF calculated with one onsite power source unavailable represents the probability of failure of operable ESF systems and remaining operable power sources during the LCO This value is determined in the process followed to calculate the incremental condition core damage probability (ICCDP) required in Regulatory Guide 1 177. The ratio of these two values (conditional CDF and baseline CDF) provides a measure of the probability of failure of operable ESF systems and remaining operable power sources during the LCO to the probability of failure of operable ESF systems and electric power sources when all electric power sources are operable.

From this CDF information it is then possible to limit the time allowed in the LCO so that the core damage probability (CDF x time in the LCO) remains at an acceptable level This acceptable level provides assurance that the LCO will remain short enough such that the probability of failure of operable ESF systems and the remaining operable electric power sources during the LCO can be considered commensurate with the probability of failure of operable ESF systems and electric power sources when all electric power sources are operable This is done using the ICCDP assessment described in Regulatory Guide 1.177

It should be noted that using the CDF parameters as an indication of this ratio is a more realistic approach than only considering the probability of failure of a certain set of systems. The CDF approach accounts for the probability of occurrence of an initiating event that requires the onsite electric power sources for mitigation while in the LCO, as opposed to the time when all onsite power sources are available. The event of interest in this case is loss of offsite power (LOSP). For example, plants that add restrictions on activities that may initiate a LOSP event or restrictions on grid reliability when the LCO can be entered, are further lowering the probability of occurrence of an event that requires onsite power sources for mitigation when in the LCO. While it is true that the reliability (and availability) of the electric power sources is higher when not in an LCO, this represents a much longer period of time, therefore, the probability of an event occurring that requires the onsite power sources for mitigation is also much higher than the time period when the unit is in the LCO.

EP RAI 3. The first bullet in Section 7.1 conveys that the likelihood of a transient occurring during the increased CT for an ac onsite electric power system has not been impacted and that some new activities may be performed on the diesel generators (DG) while at power Explain how and why these new activities will not affect or impact the likelihood of maintenance or test induced transients.

Response: A similar question was asked in PRA RAI #11 and a response provided This response is provided in the following.

As stated in Bases B3.8 (Electrical Power Systems) of the Standard Technical Specifications for Westinghouse Plants (NUREG 1431, Rev. 2), the AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18. Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The surveillance requirements for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1 9, Regulatory Guide 1 108, and Regulatory Guide 1.137, as addressed in the FSAR

The issues in this RAI are related to the availability of the DG following additional at-power preventive maintenance activities and also the potential for inducing electrical system transients during the preventive maintenance activities or during the post maintenance testing. As stated in the previous paragraph, surveillance requirements on the AC sources are designed in accordance with the noted Regulatory Guides to ensure OPERABILITY of the DGs These issues are addressed as follows

- After maintenance activities, components/systems are subject to post maintenance testing and system alignment verification Both are directed at demonstrating that the system is operable and will perform as required if demanded. These tests are performed regardless of the mode in which the testing is completed Following the DG at-power maintenance activity, a test will be completed to demonstrate operability of the DG. This test is typically the monthly DG test required in plant Technical Specifications. This monthly test is designed to be performed with the plant at-power and demonstrates DG operability

- DG maintenance activities are completed with the DG disconnected from the plant electrical distribution system. This configuration inhibits electrical transients from being introduced into the plant's electrical system

- The testing is typically completed in a configuration that will not induce electrical system transients. The test used to demonstrate DG operability is the same as that used to meet the Technical Specification monthly test requirement. This test is designed to be performed at-power and not introduce electrical system transients that could impact plant operation.

The licensees requesting this change will confirm the above in their License Amendment Request (LAR) submittals Information to be provided by each licensee includes:

- The test that will be used following at-power maintenance activities to demonstrate DG operability.

- Confirmation that the DG is disconnected from the plant's electrical system during at-power preventive maintenance activities.

- The precautions taken to ensure that plant electrical distribution system transients that could impact plant operation do not occur during the maintenance activity or follow-on testing

EP RAI 4. Section 5.1 of WCAP-15622 [i.e , the Improved Standard Technical Specifications (ISTS)] conveys that [given a system design that meets design basis requirements defined below] a 2-hour CT for an inoperable vital ac electric power source takes into account (a) the importance to safety of restoring the ac vital bus to operable status, (b) the redundant capability afforded by the other operable vital buses (i e., the CT is so short that the probability for failure of ESF systems and the remaining operable ac, dc, and vital ac electric power sources during the CT is considered commensurate with the probability for failure of ESF systems and ac, dc, and vital ac electric power sources when they are operable and not subject to a CT), and (c) the low probability of a DBA occurring during the CT Design basis requirements include.

i ESF systems are operable;
ii. ac electric power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, reactor coolant system, and containment design limits are not exceeded;
iii at least one train of safety systems will remain operable in the event of (a) an assumed loss of all offsite power and a worst case single failure, and (b) an assumed loss of all onsite ac power and a worst case single failure.

If the 2 hour CT is increased to a 24-hour CT, describe programs and activities and identify existing FSAR commitments (or proposed new FSAR or TS commitments) which are (or will be) credited to ensure that the increased CT does not impact design basis requirements Explain how, with an increased CT, the LCO will remain so short that the probability for failure of operable ESF systems and the remaining operable ac, dc, and ac vital electric power sources during the LCO can be considered commensurate with the probability for failure of operable ESF systems and operable ac, dc, and ac vital electric power sources when all electric power sources are operable

Response: This change does not impact the ability of the electrical system to mitigate design basis events. Given that a design basis event has occurred, the plant will have the same capability to mitigate the event before and after this change, and will continue to respond to design basis events in the same manner. As discussed in Sections 7.1 and 7.2 of WCAP-15622, defense-in-depth and safety margins will not be impacted by this change. Therefore, there are no new FSAR or Technical Specification commitments credited to ensure that the increased CT does not impact design basis requirements

What will be impacted by this CT increase is the availability of AC vital buses. With the extended CT, the unavailability of the AC vital buses is expected to increase slightly. Regulatory Guides 1 174 and 1.177 provide the approach and acceptance guidelines for determining an acceptable change to the plant's licensing basis using a risk-informed approach In this case, the licensing basis change is the increase to the Technical Specification CT for the AC vital buses Extending the AC vital bus CT will increase the time the buses are unavailable during power operation by a small amount, which in turn impacts the ability of the plant to respond to events Using the risk-informed approach, this impact is measured by plant risk via core damage frequency and large early release frequency.

WCAP-15622 and the supplemental analyses discussed in response to PRA RAI-8 and PRA RAI-16 presented the risk analysis results Since the impact on risk meets the guidelines in Regulatory Guide 1.174 and 1.177, the proposed change is considered acceptable from the risk perspective. Since defense-in-depth and safety margins are not impacted by this change, the CT increase is acceptable from the deterministic perspective. Therefore, the CT will remain short enough such that the probability of failure of operable ESF systems and the remaining operable ac, dc, and ac vital electric power sources while in the LCO can be considered commensurate with the probability of failure of operable ESF systems and operable ac, dc, and ac vital electric power sources when all electric power sources are operable.

EP RAI 5. Explain how (and to what extent) the risk arguments presented in the WCAP can be related to the probability for failure of operable ESF systems and remaining operable ac, dc, and ac vital electric power sources during the LCO as compared to the probability for failure of operable ESF systems and operable ac, dc, and ac vital electric power sources when all ac, dc, and ac vital electric power sources are operable.

Response: The probability of failure of the operable ESF systems and remaining operable ac, dc, and ac vital electric power sources during the LCO and the probability of failure when all ac, dc, and ac vital electric power sources are operable is not directly calculated using the risk-informed approach described in Regulatory Guides 1.174 and 1 177, nor is it required. But a measure of this can be obtained indirectly from the risk-informed approach The baseline CDF can be used to represent the probability of failure of the operable ESF systems and ac, dc, and ac vital electric power sources when all electric power sources are available This will overstate the probability of failure since this CDF value will include annual system unavailabilities due to test and maintenance activities. The conditional CDF calculated with one AC vital bus unavailable represents the probability of failure of operable ESF systems and remaining operable ac, dc, and ac vital electric power sources during the LCO. This value is determined in the process followed to calculate the ICCDP required in Regulatory Guide 1 177. The ratio of these two values (conditional CDF and baseline CDF) provides a measure of the probability of failure of operable ESF systems and operable ac, dc, and ac vital electric power sources remaining during the LCO to the probability of failure of operable ESF systems and operable ac, dc, and ac vital electric power sources when all electric power sources are operable

From this CDF information it is then possible to limit the time allowed in the LCO so that the core damage probability (CDF x time in the LCO) remains at an acceptable level. This acceptable level provides assurance that the LCO will remain short enough such that the probability of failure of operable ESF systems and the remaining operable ac, dc, and ac vital electric power sources during the LCO can be considered commensurate with the probability of failure of operable ESF systems and ac, dc, and ac vital electric power sources when all electric power sources are operable This is done using the ICCDP assessment described in Regulatory Guide 1 177.