Attachment 3

Response to NRC Request for Additional Information

(MNS only)

NRC Request for Additional Information (RAI):

By letter dated May 2, 2017 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML17122A116), as supplemented by letters dated July 20, 2017 (ADAMS Accession No. ML17201Q132) and November 21, 2017 (ADAMS Accession No. ML17325A588), Duke Energy Carolinas, LLC (Duke Energy) submitted a license amendment request (LAR) to extend the Completion Time for an inoperable diesel generator in Technical Specification (TS) 3.8.1, "AC Sources - Operating". The proposed change would also alter the AC power source operability requirements for the Nuclear Service Water System (NSWS), Control Room Area Ventilation System (CRAVS), Control Room Area Chilled Water System (CRACWS) and Auxiliary Building Filtered Ventilation Exhaust System (ABFVES) (i.e., shared systems).

On May 8-9, 2018, Duke Energy hosted a regulatory audit for the U.S. Nuclear Regulatory Commission (NRC) and its contractors to support the review of the above mentioned LAR (ADAMS Accession No. ML18117A187). In order for the NRC staff to complete its review of the request, the following additional information is requested. The Duke Energy responses pertain to McGuire Nuclear Station, Unit Nos. 1 and 2 (MNS) only. The Catawba Nuclear Station, Unit Nos. 1 and 2 (CNS) responses will be provided in a separate supplement.

APLA RAI-02 – Modeling Alternative Alignments

The LAR for MNS and CNS, dated May 2, 2017, states that the proposed change to the TS completion time has been developed using the risk-informed processes described in RG 1.174, Revision 2, and RG 1.177, Revision 1. Based on Section 2.3.1 of RG 1.177, the technical adequacy of the PRA must be compatible with the safety implications of the TS change being requested and the role that the PRA plays in justifying that change. RG 1.177 endorses the guidance provided in RG 1.200, Revision 2, on PRA technical adequacy. The RG 1.200 describes a peer review process utilizing ASME/ANS PRA standard RA-Sa-2009 as one acceptable approach for determining the technical adequacy of the PRA once acceptable consensus approaches or models have been established for evaluations that could influence the regulatory decision.

In LAR Attachment 8, Section 8.2, MNS F&O 2-7 states that for most systems included in the internal events PRA only one system alignment was modelled. The PRA standard SR SY-A5 requires that both the normal and alternate alignments be modelled to the extent needed for CDF and LERF determination. The F&O further states that there is no evidence of an investigation of alternate alignments to determine whether there may be unrecognized asymmetries important to the CDF and LERF results. Based on review of the disposition to the F&O, it is not clear to NRC staff that a review and evaluation of alternate alignments was performed to conclude that the alignments modelled in the PRAs are adequate for this LAR. NRC staff notes, based on the ICCDP risk results reported in LAR Attachment 6, that small changes in the MNS PRA modeling could potentially impact the conclusions of the LAR. To address the observations above, the staff requests the following additional information:

APLA RAI-02.a

Justify that only modeling one system alignment for most systems in the current MNS PRAs is adequate for this LAR. Include a description of the process for evaluating alternate alignments to identify whether unrecognized asymmetries important to the CDF and LERF results exist. Also, summarize the results of such an evaluation, including the identification of differences between redundant trains.

Duke Energy Response to APLA RAI-02.a:

To determine whether an alternate system alignment need be modeled, all MNS system notebooks include a "Normal and Alternate System Operation" section. The system analyst considers all possible system alignments, and determines whether the system failure probability would be different for one alignment versus another.

In general, MNS systems are designed symmetrically, such that there are the same type and number of components in each train. For these systems, the system failure probability is the same whether split fractions are applied to a multiple-alignments representation or one representative alignment is modeled. An illustrative example is provided below.

<u>A Train Operating, B Train in Standby</u>

RN system fails = (RN Train A Fails to Run) AND (RN Train B in Maintenance)

= (5E-3)(1E-2) = 5E-5

<u>Split Fraction Approach</u>

RN system fails = [(RN Train A is in Service) AND (RN Train A Fails to Run) AND (RN Train B in Maintenance)] OR [(RN Train B is in Service) AND (RN Train B Fails to Run) AND (RN Train A in Maintenance)]

= (0.5)(5E-3)(1E-2) + (0.5)(5E-3)(1E-2) = 5E-5

The SSCs Important to the 14 Day EDG Completion Time LAR for MNS are shown in LAR Table 2, repeated below. The table has been augmented to indicate the impact of modeling asymmetry.

LAR Table 2: MNS SSCs Important to the 14 Day EDG Completion Time

SSC	Reason	Modeling Asymmetries (If Any)	Impact of Modeling Asymmetry
Non-CT EDG	Maintaining AC power sources	N/A, EDGs are modeled symmetrically (both in standby)	N/A, no modeling asymmetry
ESPS	Maintaining AC power sources	N/A, ESPS is a single train	N/A, no modeling asymmetry

LAR Table 2: MNS SSCs Important to the 14 Day EDG Completion Time

SSC	Reason	Modeling Asymmetries (If Any)	Impact of Modeling Asymmetry
Component Cooling System (KC)	Maintaining capability of RCP Seal Cooling (prevent RCP seal LOCA); pump cooling and equipment cooling to mitigate transients	KC A-train pumps are assumed to be running, and KC B-train pumps are assumed to be in standby. Maintenance unavailability for both trains is summed and modeled by assigning to KC train-B.	Small, conservative impact since B-train maintenance event also includes A-train maintenance unavailability.
Turbine Driven AFW Pump (CA)	Maintaining decay heat removal capability using steam generators ("protected train" status per BTP 8-8)	N/A, the TDAFWP is a single train, aligned to all four steam generators.	N/A, no modeling asymmetry
Safe Shutdown System (SS)	Maintaining capability of RCP Seal Cooling and decay heat removal capability using steam generators	N/A, the SS system is single-train. A single reactor coolant make-up pump supplies all four reactor coolant pumps.	N/A, no modeling asymmetry

LAR Table 2: MNS SSCs Important to the 14 Day EDG Completion Time

SSC	Reason	Modeling Asymmetries (If Any)	Impact of Modeling Asymmetry
Nuclear Service Water System (RN)	Maintaining pump cooling and heat sink for ND through the KC system	RN pump 1A is assumed to be running and RN pumps 1B, 2A and 2B are assumed to be in standby. B-train supply and discharge valves align to the Standby Nuclear Service Water Pond on Loss of Offsite Power or Safety Injection signal. Power to move the 1B-Train RN suction and discharge valves is supplied from Unit 2. Modeling of maintenance basic events is included for the standby pump trains as well as for shared B-train supply and discharge headers.	LAR Attachment 6 notes that "the 1B-Train RN suction and discharge valves are designed to swap over from the low level intake to the Standby Nuclear Service Water Pond (SNSWP) following a loss of power on the 1B-Train, and because power to move the 1B-Train RN suction and discharge valves comes from the 2B-Train, the 1B-Train of RN is conservatively modeled as failing when normal power fails to 2ETB and the 2B-EDG fails to provide power to 2ETB. This is of particular concern during dual-unit LOOP events. Since A-Train RN valves are not designed to swap over to the SNSWP on loss of power to 1ETA, this RN failure would not occur when aligning ESPS to 1ETA. Conservatively, B-train maintenance events also include A-train maintenance unavailability.
Chemical and Volume Control (NV)	Maintaining capability of RCP Seal Cooling	NV pump A is assumed to be running, and NV pump B is assumed to be in standby. Maintenance unavailability for both trains is summed and modeled by assigning to train B.	Small, conservative impact since B-train maintenance event also includes A-train maintenance unavailability.

LAR Table 2: MNS SSCs Important to the 14 Day EDG Completion Time

SSC	Reason	Modeling Asymmetries (If Any)	Impact of Modeling Asymmetry
Diesel Air Compressor G (VI)	Maintaining control to Air Operated Valves	N/A, one of two redundant, independent compressors that auto-starts to provide a back-up air supply.	N/A, no modeling asymmetry
Diesel Air Compressor H (VI)	Maintaining control to Air Operated Valves	N/A, one of two redundant, independent compressors that auto-starts to provide a back-up air supply.	N/A, no modeling asymmetry
Residual Heat Removal (ND)	Maintaining decay heat removal capability	N/A, ND pump trains are modeled symmetrically (both in standby)	N/A, no modeling asymmetry
Motor Driven AFW Pumps (CA)	Maintaining decay heat removal capability using steam generators	N/A, the MDAFWP trains are modeled symmetrically (both in standby)	N/A, no modeling asymmetry
Switchyard	Maintaining availability of off-site power	N/A, loss of offsite power from the switchyard modeled using initiating events that fail all normal power to the unit.	N/A, no modeling asymmetry

APLA RAI-02.b

If a justification cannot be provided regarding the MNS PRAs only modelling one system alignment for most systems, then incorporate the alternate alignments important to CDF and LERF into the MNS PRA models used for this LAR that aggregate the PRA updates requested in APLA RAI-14.

Duke Energy Response to APLA RAI-02.b:

Based on the response to APLA RAI-02a above, modeling only one system alignment for most systems in some of the MNS PRA models is adequate for this LAR because CDF and LERF are nonetheless quantified appropriately. The modeling of maintenance unavailabilities was noted to have been performed in a conservative fashion since all maintenance was accounted for by including it on the standby components. In addition, the assignment of ESPS to train B was noted as being conservative with respect to the MNS RN system due to the train asymmetries identified in Table 2 above.

APLA RAI-04 – Exceedance of RG 1.177 Risk Acceptance Guidelines Using NUREG-2169 Fire Ignition Frequencies

Section 2.5.3 of RG 1.174, Revision 2, states, "[t]he impact of using alternative assumptions or models may be addressed by performing appropriate sensitivity studies or by using qualitative arguments, based on an understanding of the contributors to the results and how they are impacted by the change in assumptions or models." In addition, Section 2.5.5 of RG 1.174 states, "[i]n general, the results of the sensitivity studies should confirm that the guidelines are still met even under the alternative assumptions (i.e., change generally remains in the appropriate region)."

Based on LAR Attachment 6, Section 6.2.4, the fire PRA does not incorporate the most current fire ignition frequencies from NUREG-2169, "Nuclear Power Plant Fire Ignition Frequency and Non-Suppression Probability Estimation Using the Updated Fire Events Database, United States Fire Event Experience Through 2009," dated January 2015 (ADAMS Accession No. ML15016A069). The LAR Section 6.2.4 presents the results of a sensitivity study that shows the impact of using the fire ignition frequencies from NUREG-2169 on the ICCDPs and the ICLERPs. Tables 6-50 and 6-52 presented in the LAR Section 6.2.4 show an increase from the baseline CDF of between 20 and 22 percent for CNS and 25 percent for MNS from using the updated fire ignition frequencies provided in NUREG-2169. The tables also show an increase in baseline LERF between 32 and 34 percent for CNS and 33 percent for MNS. Table 6-53 in the LAR Section 6.2.4 shows the results of the "adjusted analyses" (to produce the ICCDP and ICLERP values) for MNS to be above the RG 1.177 risk acceptance guidelines of 1E-06 for ICCDP and 1E-07 for ICLERP.

In accordance with regulatory guidance, provide a detailed justification for not using the most current fire ignition frequencies provided in NUREG-2169 to support the conclusion of the LAR that the risk acceptance guidelines in RG 1.177 are met for MNS when using the updated fire frequencies from NUREG-2169. The justification should be based on understanding the contributors to the results and how they can be impacted by changes in assumptions or models. Include a discussion of the conservatisms in the analysis and the risk significance of these conservatisms. [Note, the results of the sensitivity study in LAR Section 6.2.4 and discussed in this RAI may change due to APLA RAI-14, as such, the response to this RAI should be relative to the latest LAR results.

Duke Energy Response to APLA RAI-04:

As was noted in the LAR submittal, there were potential impacts from multiple new NRC fire guidance documents. Only the potential negative impact due to the increase in fire frequency from NUREG-2169 was evaluated in the fire portion of the aggregated sensitivity. The reduction in peak heat release rate from NUREG-2178 would result in a decrease in fire impact. The impact of NUREG-2178 was not calculated as it would require re-evaluating fire scenarios for the sources.

The ignition frequencies from NUREG-2169 were used to update the fire scenario frequencies in the ESPS McGuire fire model. The results of the updated fire frequencies are included in the aggregated results, as shown in Duke Energy responses to APLA RAI-14, that demonstrate margin to the Regulatory Guide 1.177 CT ICCDP and ICLERP limits.

APLA RAI-05 – Basic Event Failure Rate Anomalies

Section 5, "Quality Assurance," of RG 1.174, Revision 2, states, "[w]hen a risk assessment of the plant is used to provide insights into the decision making process, the PRA is to have been subject to quality control."

NRC staff noted in LAR Attachment 7, "PRA Quantification Data Tables," which provides a listing of basic events and their corresponding probabilities, some apparent anomalies that could impact the LAR. The staff requests the following information to address these basic event anomalies:

APLA RAI-05.a

It was observed that diesel generator basic events for the same failure mode (fail-to-start (FTS), fail-to-load/run (FTLR), and fail-to-run (FTR)) were assigned different probabilities in the PRAs for different hazards for each class of diesel generator (i.e., EDG, Standby Shutdown Facility (SSF), and ESPS). For example, basic event 1JDG001ADGS from the CNS internal events PRA, which is represented by basic event JDG001ADGS in the other CNS hazard models, is assigned three different failure probabilities across the CNS hazard group PRA models (i.e., the internal flooding, fire, and high winds PRAs). Basic event JDG001ADGS from the MNS internal events PRA is assigned two different failure probabilities across the MNS hazard group PRA models. It appears that the source of some of these anomalies in the MNS internal events PRA basic events may have been caused by using events from the CNS hazard group PRA models (e.g., MNS internal events basic event JDG001ADGS is used in the CNS high winds and fire PRA models instead of 1JDG001ADGS). To address the above observations, provide the following information:

i. Explain the apparent inconsistent application of diesel generator (i.e., EDG, SSF, ESPS) failure probabilities across the site's hazard group PRA models. As part of the discussion, describe each site's process to ensure data consistency across the site's PRA models. Justify any anomalies in diesel generator failure probabilities that will be retained in the risk assessment supporting this LAR.

ii. If basic events used in the CNS model are from MNS (or vice versa), describe Duke Energy's process to ensure determination of basic event probabilities are appropriate for the plant's PRA model(s).

iii. If the apparent anomalies in diesel generator failure probabilities cannot be justified, then incorporate the appropriate generator failure probabilities into the PRA models used for this LAR that aggregate the CNS and MNS PRA updates requested in APLA RAI-14.

Duke Energy Response to APLA RAI-05.a:

i. Since the different hazard models are updated at different times, the data sources have varied with the latest information at the time of the update.
ii. The corresponding site specific diesel failure rates were used consistent with the peer reviewed models.
iii. To address the concern, the latest site specific diesel failures will be used for the SSF and Emergency Diesel Generators in the aggregate sensitivity analysis presented in Duke Energy responses to APLA RAI-14. The ESPS diesel used the generic fail to start and fail to run probabilities from the 2016 update of the NUREG-6928 data for station blackout diesels.

The failure rates used for the diesel failures are listed below.

MNS Failure Rates for DGs Across Hazards

Hazard	EDG run (/hr)	ESPS DG run (/hr)	SSF DG run (/hr)	EDG start	ESPS DG start	SSF DG start	EDG load/run (/hr)	SSF DG load/run (/hr)
*IE	7.77E-4	1.50E-3	8.21E-4	2.87E-3	2.98E-2	2.34E-3	2.59E-3	1.54E-3
IF	7.77E-4	1.50E-3	8.21E-4	2.87E-3	2.98E-2	2.34E-3	2.59E-3	1.54E-3
HW	7.77E-4	1.50E-3	8.21E-4	2.87E-3	2.98E-2	2.34E-3	2.59E-3	1.54E-3
SEISMIC	7.77E-4	N/A	N/A	2.87E-3	N/A	N/A	2.59E-3	N/A
FIRE	7.77E-4	1.50E-3	8.21E-4	5.46E-3	2.98E-2	3.88E-3	Added to start	Added to start

*indicates that the data set is the most current for the model

APLA RAI-05.b

It was observed that in some cases the ESPS and SSF diesel generators had the same failure rate as the Class 1E EDGs (specifically, the fail-to-start values). It is noted that the generic industry fail-to-start rate since 2010 is an order of magnitude higher for non-safety-related diesel generators than for Class 1 EDGs.

i. Provide clarification of how the CNS and MNS SSF and ESPS diesel generators were classified when assigning industry data (i.e., were they classified as an EDG, hydraulic turbine generator (HTG), combustion turbine generator (CTG), or station blackout generator (SBOG)). As part of the response, justify why the failure rates used for the SSF and ESPS diesel generators appear to be equivalent to the failure rates used for the Class 1E EDGs.

ii. If the use of safety-related failure rates for non-safety equipment cannot be justified, then incorporate the appropriate probabilities into the CNS and MNS PRA models used for this LAR that aggregate the PRA updates requested in APLA RAI-14.

Duke Energy Response to APLA RAI-05.b:

i. The SSF failure rates presented in the LAR were developed using generic diesel rates and partitioning them out by size, and then updating with plant-specific data (both plants underwent this same method).

ii. For the SSF diesel generators, a study of diesel generator reliability was developed. A part of this study dealt with the influence of diesel generator output on reliability and indicated that smaller diesel generators at nuclear facilities tended to have somewhat better reliability. The output of the standby shutdown facility (SSF) diesel generator at both MNS and CNS is on the order of 750 kW which is significantly smaller than the emergency diesel generators. It is also less complex. To provide a better generic estimate for this component, the observations from the work developed in the study are used to adjust the baseline generic failure data from NUREG/CR-6928. The study concluded that diesels with capacities less than 2500 kW show a reduction on failure rates of 57 percent for the failure to start failure mode and 40 percent for the failure to run failure mode as compared to the other diesel generator sizes. Further, the study of the available data indicated that the use of diesels within this size range could result in a reduction in station blackout frequency. The study was based on an assessment of operational data for 52 U.S. nuclear power plants and collected data based on diesel generator output, testing duration, failure and count data. Precautionary stops were counted in the baseline assessment as failures and a sensitivity performed that excluded these events. The data was sorted based on diesel generator size. Seven size ranges were initially chosen. These were: less than 1500 kW, 1500-2000 kW, 2000-2500 kW, 2500-3000 kW, 3000-3500 kW, 3500-4000 kW, and greater than 4000 kW. Each diesel was placed into one of the size ranges and the total number of start and run failures tabulated. Totals for diesel generator demands and run hours were also generated for each size range. The results presented in a normalized fashion are presented in Table 1. The failure rate is normalized to the average value.

Table 1. Baseline Diesel Generator Failure Rates

Diesel Output	Population	Fails to Start	Fails to Run
<1500 kW	5	4.72E-1	7.93E-1
1500 - 2000 kW	8	4.85E-1	NFR[1]
2000 - 2500 kW	19	8.56E-1	7.26E-1
2500 - 3000 kW	73	1.16E+0	1.03E+0
3000 - 3500 kW	4	1.38E+0	2.26E+0
3500 - 4000 kW	27	1.60E+0	9.89E-1
>4000 kW	17	1.05E+0	1.22E+0
Average	153	1.00E+0	1.00E+0

1. No failures reported

Table 1 shows that a trend is clearly visible for the start failure and that in general there is an increasing failure to run rate as size increases. Given that the SSF diesel generators are less than 1500kW the reduction factor is 47.2% for fails to start and 79.3% for fails to run. These factors are used to adjust the parameters for the uncertainty characteristics. The alpha parameter is representative of the number of failures while the beta parameter is associated with the number of hours or demands. The number of trials (hours or demands) is not changed by improved reliability and the beta parameter remains constant. The alpha factor, however, is reduced by the factor to account for a corresponding reduction in the number of failures. Table 2 provides a summary of the calculation process.

Table 2
Development of SSF Diesel Generator Failure Rate

Failure Mode	Reference 17 Parameters		Reduction Factor	Revised Parameters		Updated Mean Value	Units
	α	β		α	β		
Fails to Start	8.111	2.798E+3	0.472	3.828	2.798E+3	1.37E-3	N
Fails to Load/ Run	2.774	7.311E+2	0.472	1.309	7.311E+2	1.79E-3	N
Fails to run	4.487	4.093E+3	0.793	3.558	4.093E+3	8.69E-4	H

Plant-specific failures were factored into the final probability rates for each plant's model.

For the aggregate sensitivity presented in Duke Energy responses to APLA RAI-14, the generic failure rates for station blackout diesels from the 2016 update of NUREG-6928 data was used for the ESPS diesel generators.

APLA RAI-06 – ESPS Operator Action HRA Anomalies

Section 5, "Quality Assurance," of RG 1.174, Revision 2, states, "[w]hen a risk assessment of the plant is used to provide insights into the decision making process, the PRA is to have been subject to quality control."

NRC staff noted anomalies in LAR Attachment 6 regarding the addition of HFEs to the PRA hazard models and LAR Attachment 7 regarding the use of different HEP values for the same HFE used in the PRA hazard models. The staff requests the following information to address these anomalies:

APLA RAI-06.a

As discussed in Attachment 6 of the LAR, two HFEs were developed for the ESPS in both the CNS and MNS PRAs. One HFE (i.e., 0OPER-ESPS14 for CNS and JESPS14DHE for MNS) is applied to the extended CT model case and is described in LAR Attachment 6, Section 6.1.4.1 as, "Operator Fails to Power 4kV Bus from ESPS During 14 Day AOT." The other HFE (i.e., 0OPER-ESPSNA for CNS and JESPSNADHE for MNS) is applied when the EDG is available (e.g., non-extended CT model case) and is described as, "Operator Fails to Power 4kV from ESPS when Not Aligned for 14 Day AOT." The LAR Section 6.1.4.1 states that the HEP for the non-extended CT HFE (i.e., 0OPER-ESPSNA for CNS and JESPSNADHE for MNS) is assigned a screening value of 0.1 and the HEP for the extended CT HFE (i.e., 0OPER-ESPS14 for CNS and JESPS14DHE for MNS) is assigned a value 5.4E-02.

The LAR Attachment 7 tables appear to indicate that the ESPS HEP values are not consistently applied across all hazard group PRAs. For example, human failure event JESPSNADHE (which is assigned to the non-extended CT case) is assigned the value of 5.4E-02 in both the CNS fire PRA importance results [presented in LAR Tables 7-44, 7-47, 7-50, and 7-53 and described as, "Operator Action to power 4kV from ESPS when Not Aligned for 14 Day AOT"] and in the MNS fire PRA importance results [presented in LAR Tables 7-56, 7-59, 7-62, and 7-65 and described as, "Operator Fails to power 4kV from ESPS"], but this HFE is assigned a value of 0.1 in the original internal events analysis as explained earlier. To address the above observations, provide the following information:

i. Explain the apparent inconsistent application of HEP values for the same ESPS HFEs cited above across each site's hazard group PRA models.

ii. Justify any anomalies in the cited HEPs that will be retained in the risk assessment supporting this LAR.

ii. If the use of the apparent inconsistent HEP values cannot be justified, then apply the correct HEPs to the CNS and MNS PRA models used for this LAR that aggregate the PRA updates requested in APLA RAI-14.

Duke Energy Response to APLA-RAI-06.a:

i. The values applied for the recovery HEP for Hazard are listed below. The appropriate values were used. The nominal base CDF/LERF were calculated without crediting ESPS so there are no HEP values.

MNS ESPS Alignment Action

Hazard	Configuration	Basic Event Name	Recovered Value	Additional Information
Fire	AOT	JESPSNADHE	5.40E-02	Recovered with XESPSNADHE
Fire	non-AOT	JESPSNADHE	1.00E-01	Recovered with XESPSNADHE
HW	AOT	JESPSNADHE	5.40E-02	
HW	non-AOT	JESPSNADHE	1.00E-01	
IE	AOT	JESPS14DHE	5.40E-02	
IE	non-AOT	JESPSNADHE	1.00E-01	
IF	AOT	JESPS14DHE	5.40E-02	
IF	non-AOT	JESPSNADHE	1.00E-01	

ii. There are no anomalies for McGuire.

iii. Not applicable since there are no inconsistencies.

APLA RAI-06.b

The NRC staff observed that the CNS high winds PRA model (based on LAR Tables 7-31 through 7-36) utilizes an HFE (i.e., JESPS14DHE) which is identified in LAR Attachment 6, Section 6.1.4.1 as being specific to the MNS PRAs.

i. If the HFEs used in the CNS model are from MNS (or vice versa), describe Duke Energy's process to ensure determination of HFE probabilities are appropriate for the plant's PRA model(s).

ii. Confirm that the ESPS HFEs and HEPs are correct for both CNS and MNS (take into account the HFEs described in Part a). If there are incorrect ESPS HFEs and HEPs used in the CNS or MNS PRAs, then incorporate the correct HFEs and HEPS into the PRA models used for this LAR that aggregate the PRA updates requested in APLA RAI-14.

Duke Energy Response to APLA RAI-06.b:

i. The critical actions required to utilize the ESPS diesels are common to both sites and ESPS arrangements. Before exercising the extended Diesel CT, the ESPS system will need to be incorporated into the model using the as-built/as operated characteristics of the systems to properly monitor the risk per 10 CFR 50.65 A(4) program. With this incorporation, the remaining HEP actions will be evaluated for the ESPS related procedural steps and HRA dependencies will be evaluated per the PEER reviewed methods.

ii. The aggregate sensitivity case uses the limiting two times the values listed above for comparison to the Regulatory Guide 1.177 14 day CT ICCDP and ICLERP limits.

APLA RAI-07 – Reasonableness of HEPs for ESPS operator actions

The LAR states that the proposed change to the TS completion time has been developed using the risk-informed processes described in RG 1.174, Revision 2, and RG 1.177, Revision 1. Based on Section 2.3.1 of RG 1.177, the technical adequacy of the PRA must be compatible with the safety implications of the Technical Specification change being requested and the role that the PRA plays in justifying that change. Based on Section 2.3.2 of RG 1.174, the risk assessment supporting a risk-informed LAR should properly account for the effects of the changes on operator actions.

Based on the risk assessment results presented in LAR Attachment 7 for CNS and MNS, operator failures associated with implementing ESPS are a significant contributor to the change in risk results for this LAR. This demonstrates the importance of calculating realistic HEPs for these operator actions. In addition, the licensee does not have the applicable procedures in place for these actions, which queries the validity of the analysis of these actions. Therefore, the NRC staff has a general need to confirm the reasonableness of these calculations.

In addition, Sections 3.1.2 and 3.2.2 of the LAR for CNS and MNS describe the EDG load sequencer associated with the station blackout (SBO) signal, but there is no mention of load sequencing of the Engineered Safety Features (ESF) bus that has lost power and must be restored by the ESPS system. Section 6.1.4.1 in LAR Attachment 6 does not describe how the required ESF loads are aligned for the scenarios that involve the ESPS system. The NRC staff is unclear if additional restoration actions have been excluded from the ESPS model logic.

To address the above observations, provide the following information:

APLA RAI-07.a

Describe the operator actions associated with ESPS that are required to start, perform load sequencing, and align ESF loads. Identify whether these actions are included in the PRA model used to support the LAR.

Duke Energy Response to APLA RAI-07.a:

The HEP for operator action to use the ESPS system consists of the following actions:

Opening of the Normal Incoming power breaker

Push button start of the ESPS system

Position of Kirk-Key interlock to allow emergency bus to be powered by ESPS system

Load Shed – manual (confirmation of automatic action)

Closing in of ESPS breaker to bus

Placing required emergency loads on bus

These actions were assessed and included in the execution portion of the HEP failure probability calculation.

APLA RAI-07.b

For the operator actions identified in Part a, provide the following additional information:

i. For those operator actions not modeled in the PRA, but required in Part a, provide a justification for not modeling these actions.

ii. For those operator actions used to support the ESPS function that were previously used in the PRA whose HEPs were not modified in support of the LAR (e.g., to reflect use of revised procedure(s) and different timing analyses), provide sufficiently detailed justification for not modifying these HEPs.

iii. For those operator actions used to support the ESPS function that were previously used in the PRA whose HEPs were modified in support of the LAR (e.g., to reflect updated manpower utilization and different timing analyses), justify how these HEPs were modified and that the inputs used are appropriate.

iv. For those new operator actions added to the PRA in support of the LAR, explain how their HEPs were developed. Provide sufficient details to justify the basis for these HEPs.

v. If any HFEs/HEPs discussed in Parts (i) through (iv) cannot be justified, then modify the HRA using a justifiable basis and incorporate the results into the CNS and MNS PRA models used for this LAR that aggregate the PRA updates requested in APLA RAI-14. Explain how the HRA was modified and provide sufficient details to justify the basis for the modification(s).

Duke Energy Response to APLA RAI-07.b:

Part b.i.

Critical actions for this HEP were included in part a of this response. No additional justification required.

Part b.ii.

Currently the use of the ESPS system is assumed to occur after the other possible actions to recover AC power have been attempted. No changing to timing analysis would be required.

Part b.iii.

Currently the use of the ESPS system is assumed to occur after the other possible actions to recover AC power have been attempted. No changing to man power limitations would be required.

Part b.iv.

THERP was used for the execution failure probabilities. No recovery credit was applied, even though the lack of power to the emergency bus to load on required emergencies loads would be a very clear indication that the initial attempt to use ESPS was not successful.

Part b.v.

Since the procedures for the operator action have not been developed, the HEP failure probability was doubled and the impacts of this increase are included in the aggregate sensitivity for comparison to the Regulatory Guide 1.177 14 day CT ICCDP and ICLERP limits.

APLA RAI-08 – Seismic Analysis Contribution to the Application

Section 2.3.2 of RG 1.177, Revision 1, states, "[t]he scope of the analysis should include all hazard groups (i.e., internal events, internal flood, internal fires, seismic events, high winds, transportation events, and other external hazards) unless it can be shown that the contribution from specific hazard groups does not affect the decision."

The impact of seismic risk on the LAR was estimated using a bounding approach, but aspects of how Duke Energy applied seismic risk contribution to overall risk values generated for the LAR are not clear.

APLA RAI-08.a

Section 6.1.5.7 of LAR Attachment 6 states a seismic bounding analysis was performed for both CNS and MNS in which the assessment did not credit the ESPS for the hazard interval up to the safe shutdown earthquake (SSE) level. The LAR states that the hazard interval including the SSE is assumed to result in a dual unit loss of offsite power (LOOP) with no credit for offsite power recovery. Section 6.1.5.7 of LAR Attachment 6 presents seismic CDF and LERF increases for a 14-day CT determined using the seismic bounding analysis. The footnotes to Tables 6-26 through 6-37 of the LAR state that "[s]eparate base case and CT case values were not generated since no seismic PRA exists." Without a seismic PRA model or partial seismic PRA, it is not clear how the bounding seismic CDF and LERF increases were determined. Describe and justify the modeling that was performed to determine the bounding seismic CDF and LERF increases.

Duke Energy Response to APLA RAI-08.a:

To assess the CDF and LERF impact of ESPS in response to a design basis seismic event level, the internal events model was used to determine the resulting conditional core damage probability (CCDP) and conditional large early release probability (CLERP). In addition, the following lists key assumptions and bounding conditions considered in the assessment:

1. The desired diesel maintenance window with ESPS available is 14 days.
2. The most recent site-specific seismic hazard data is used for this assessment.
3. This assessment does not include a low magnitude earthquake not resulting in a LOOP which is subsumed in the internal events PRA model. Considering a generic High Confidence of Low Probability of Failure (HCLPF) of 0.1g for a seismic-induced LOOP event, the lower bound acceleration hazard interval of interest for this assessment is defined as 0.1g. Therefore, earthquakes up to this acceleration level are not assumed to fail offsite power.
4. The plant is operating 'at-power' at the time of the event.
5. The LOOP event affects both units (i.e., no recovery from opposite unit). Offsite power is not assumed to be recovered.
6. The 'A' trains of equipment are operating with the 'B' trains in standby.
7. The comparative case includes the 'B' diesel generator out of service for testing and maintenance when the seismic event occurs. The opposite unit's diesels are protected. All other equipment is available with their maintenance events retained at their nominal values.
8. The ESPS diesel generator fails in response to the seismic hazard interval of interest under consideration, which includes the SSE. (This is a conservative assumption.)
9. For McGuire, it is assumed that the SSF structure is not available following the seismic event. (This same assumption was made for the IPEEE submittal.)
10. The HRA values were not adjusted in response to the seismic hazard interval of interest.

The delta seismic CDF and LERF was evaluated over the latest McGuire seismic hazard. Using Table A-1a of the McGuire seismic hazard report[1], the mean probability of exceedance at peak ground acceleration (pga) at various points along the hazard was obtained. (This is depicted both graphically and in tabular form:

[1] Lettis Consultants International, Inc.; "McGuire Seismic Hazard and Screening Report; Calculation of Seismic Hazards for CEUS Sites"; Project No. 1041; October 2013

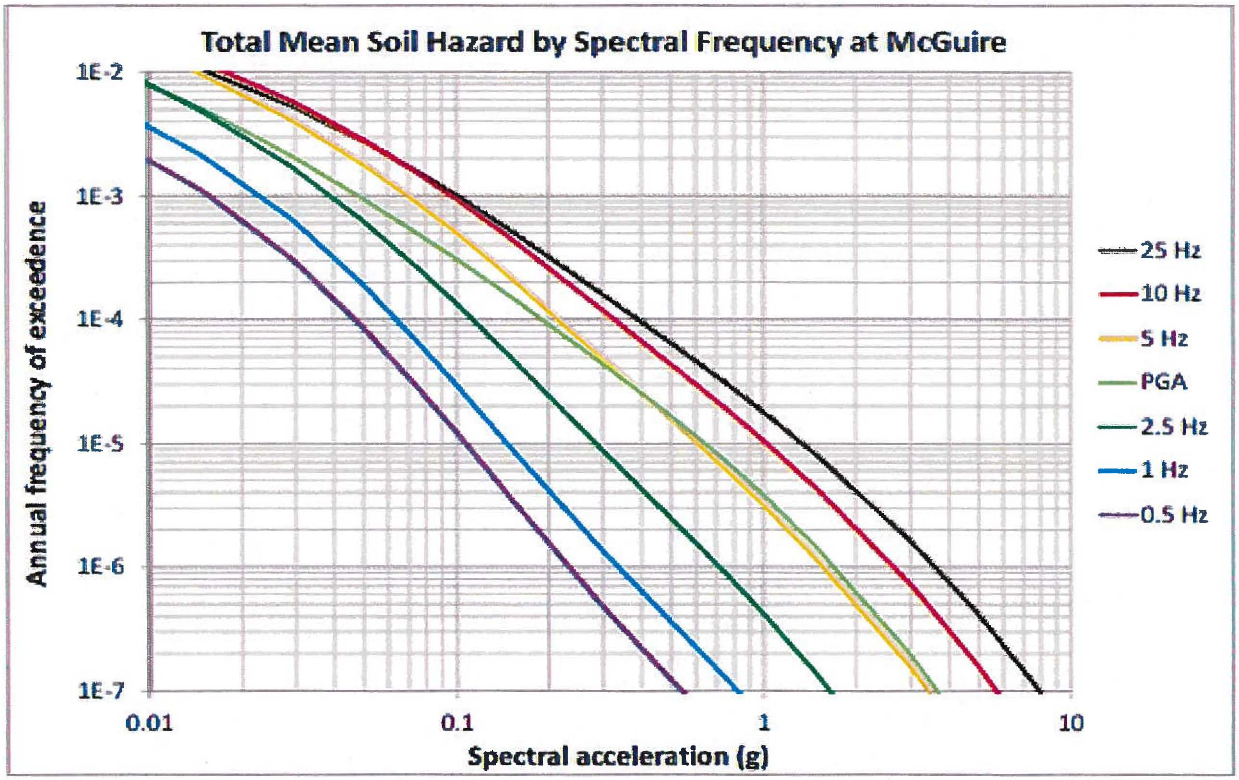

Table A-1a. Mean and Fractile Seismic Hazard Curves for PGA at McGuire

AMPS(g)	MEAN	0.05	0.16	0.50	0.84	0.95
0.0005	5.21E-02	3.33E-02	4.43E-02	5.27E-02	6.00E-02	6.54E-02
0.001	4.15E-02	2.35E-02	3.42E-02	4.19E-02	4.98E-02	5.50E-02
0.005	1.58E-02	7.03E-03	1.08E-02	1.53E-02	1.95E-02	2.92E-02
0.01	8.18E-03	3.28E-03	4.77E-03	7.45E-03	1.04E-02	1.90E-02
0.015	5.16E-03	1.82E-03	2.64E-03	4.43E-03	6.83E-03	1.38E-02
0.03	2.07E-03	5.20E-04	7.77E-04	1.49E-03	2.96E-03	7.13E-03
0.05	9.66E-04	1.79E-04	2.80E-04	5.91E-04	1.40E-03	3.90E-03
0.075	5.06E-04	7.66E-05	1.27E-04	2.80E-04	7.13E-04	2.19E-03
0.1	3.14E-04	4.37E-05	7.45E-05	1.72E-04	4.31E-04	1.38E-03
0.15	1.56E-04	2.07E-05	3.79E-05	8.85E-05	2.16E-04	6.64E-04
0.3	4.50E-05	5.66E-06	1.16E-05	2.84E-05	6.73E-05	1.57E-04
0.5	1.70E-05	1.98E-06	4.31E-06	1.13E-05	2.72E-05	5.27E-05
0.75	7.41E-06	7.77E-07	1.72E-06	4.90E-06	1.21E-05	2.25E-05
1.	3.92E-06	3.63E-07	8.23E-07	2.53E-06	6.54E-06	1.21E-05
1.5	1.46E-06	1.07E-07	2.53E-07	8.72E-07	2.46E-06	4.83E-06
3.	2.03E-07	7.55E-09	2.10E-08	9.79E-08	3.23E-07	7.77E-07
5.	3.50E-08	7.34E-10	2.22E-09	1.32E-08	5.20E-08	1.55E-07
7.5	7.02E-09	1.77E-10	3.63E-10	2.13E-09	9.51E-09	3.47E-08
10.	1.99E-09	1.16E-10	1.64E-10	5.66E-10	2.57E-09	1.05E-08

The hazard was divided into six segments, or "bins", to provide an assessment over relatively uniform intervals. The bins selected are shown below (Note: the last bin encompasses all earthquakes greater than 1.0g).

Bin No.	Lower Bound (g)	Upper Bound (g)
1	0.1	0.15
2	0.15	0.3
3	0.3	0.5
4	0.5	0.75
5	0.75	1
6	>1	-------

The Safe Shutdown Earthquake (SSE) for McGuire is 0.15g[2]. From Table A-1a above, the mean probability of exceedance at peak ground acceleration (pga) for McGuire's SSE of 0.15g is 1.56E-04 / yr. Similarly, for the LOOP HCLPF value of 0.1g, the probability of exceedance is 3.14E-04 / yr. Applying the VLOOKUP function in EXCEL, the delta between these two probabilities is 1.58E-04 / yr. Since the hazard is plotted on a log scale, the midpoint between the two acceleration levels can be determined by adding the lognormal value of the upper and lower bounds and dividing by 2. This results in a value of 0.1225g. Finally, the LOOP fragility for the bin is calculated by applying a normal distribution of the bin midpoint and the generic LOOP fragility from NUREG / CR-6544[3] as follows:

Norm. Distr. (ln (midpoint / LOOP frag. median) / LOOP frag. βc) =

Norm. Distr. (ln (0.1225 / 0.3) / 0.54) = 0.048812

This process was repeated for all six bins, resulting in the following:

Bin No.	Lower Bound (g)	Upper Bound (g)	Frequency Contribution (g)	Midpoint (g)	LOOP Bin Fragility
1	0.1	0.15	1.58E-04	0.122	0.049
2	0.15	0.3	1.11E-04	0.212	0.261
3	0.3	0.5	2.80E-05	0.387	0.682
4	0.5	0.75	9.59E-06	0.612	0.906
5	0.75	1	3.49E-06	0.866	0.975
6	>1	-------	3.92E-06	3.0	1

Next, the McGuire Rev. 4 (MR4) internal events model was used to determine the resultant conditional core damage probability (CCDP) and conditional large early release probability

[2] McGuire UFSAR, Chapter 3

[3] NUREG / CR-6544; A Methodology for Analyzing Precursors to Earthquake-Initiated and Fire-Initiated Accident Sequences; April 1998

(CLERP) contributions from each bin. Accordingly, the fault tree was modified by replacing the LOOP (%T3) initiator with the values determined above. All other initiators were set to 0. The CDF module was then solved and the resulting CDF was 5.85E-08/ yr. Thus, for a 14-day window, the CCDP is:

5.85E-08/yr x (14 days / 365 days/yr) = 2.24E-09

Next, for the comparative case, the 'B' EDG unavailability value was set to 1.0 and the 'A' EDG unavailability value was set to 0. The resulting CDF was 7.55E-07/ yr. Thus, for a 14-day window, the CCDP is:

7.55E-07/yr x (14 days / 365 days/yr) = 2.90E-08

Therefore, the delta CCDP is,

2.90E-08 - 2.24E-09 = 2.68E-08

Similarly, the LERF module was solved resulting in a value of 2.41E-08/ yr. Thus, for a 14-day window, the CLERP is:

2.41E-08/yr x (14 days / 365 days/yr) = 9.24E-10

For the comparative case, the resulting LERF was 2.86E-07/ yr. Thus, for a 14-day window, the CLERP is:

2.86E-07/yr x (14 days / 365 days/yr) = 1.10E-08

And the delta CLERP is,

1.10E-08 - 9.24E-10 = 1.01E-08

APLA RAI-08.b

For a number of cases in the LAR where risk results are presented, including LAR Attachment 6, Section 6.1.5.7, the results provide or include seismic CDF and LERF results based on the seismic bounding analysis. While in other cases, the seismic CDF and LERF contribution is excluded. For example, the last four entries in Table 6-23 lists the ICCDP and ICLERP values for CNS non-14 day CT risk, which could be verified by NRC staff to exclude the seismic values contribution, and the same observation was made for the middle two entries of LAR Table 6-25. Also, based on assessment of LAR Table 6-24 and the last two entries in Table 6-25 using values provided in other tables of the LAR, it appears that the seismic contribution for the CT cases is included but is excluded for the non-CT cases. Other apparent inconsistencies were also noted. To address the above observations, the staff requests the following additional information:

i. Provide clarification for LAR Table 6-23 for why seismic values were excluded for the non-14 day CT case when they appear to have been included in the other calculations.

ii. For Tables 6-24 and 6-25 of the LAR, explain how the values presented are calculated (note, this same information is also in Tables 3 and 4 of the LAR).

Include clarification and justification of how the seismic contribution is incorporated.

iii. Explain why the change in CDF (ΔCDF) value for seismic presented in LAR Tables 6-26 through 6-29 is not the same as the much lower and presumably correct value of 5.79E-07 presented in LAR Attachment 6, Section 6.1.5.7. This inconsistency is also noted for the change in LERF (ΔLERF) for the apparent correct value of 1.02E-07 presented in LAR Attachment 6, Section 6.1.5.7, compared to the values used in LAR Tables 6-30 through 6-33.

iv. If incorrect seismic CDF and LERF values were used or were incorrectly applied to the risk estimates determined for this application, then apply the correct seismic CDF and LERF values or apply them correctly to the risk estimates determined for this application after new PRA results are generated in response to APLA RAI-14. Present these revised seismic risk values.

Duke Energy Response to APLA RAI-08.b:

i. For the LAR submittal, the bounding seismic risk was evaluated for the CT case only as the baseline seismic risk could not be computed due to a lack of seismic PRA. This is why seismic values were included for the CT cases in Table 6-25 while they were excluded for the non-CT cases and the baseline case where the ESPS is loaded, but no credit taken for analysis.

ii. In the LAR submittal, Table 6-24 applies to CNS and will be addressed in a separate supplement. Table 6-25 presents differences in ICCDP and ICLERP between the CT and non-CT cases for MNS. The ICCDP difference is computed by subtracting the CT ICCDP from the non-CT ICCDP (e.g., 5.04E-06 (ICCDP difference) = 5.97E-06 (non-CT ICCDP) – 9.27E-07(CT ICCDP)). The CT ICCDP of 9.27E-07 in Table 6-25 can be obtained by multiplying the CT delta CDF of 2.42E-05 (See Table 6-34) with 14/365 while the non-CT ICCDP of 5.97E-06 can be obtained by multiplying the non-CT delta CDF of 6.21E-06 (See Table 6-46) with 351/365. The bounding seismic CDF was only considered for those cases where the ESPS is aligned to the emergency bus during AOT (i.e., CT CDF) while it is not included in the baseline and non-CT CDF values. The same process is used for computing the ICLERP difference in Table 6-25.

iii. The updated analysis results presented in response to APLA RAI-08.a uses the equations given in Regulatory Guide 1.177 ICCDP and ICLERP. The new analysis has CDF/LERF values for both the base and CT cases.

iv. The seismic analysis described in APLA RAI-08.a was used in the aggregate sensitivity case and the results are within the Regulatory Guide 1.177 14 day CT ICCDP and ICLERP limits.

APLA RAI-09 – External Events Analysis

Section 2.3.2 of RG 1.177, Revision 1, states, "[t]he scope of the analysis should include all hazard groups (i.e., internal events, internal flood, internal fires, seismic events, high winds, transportation events, and other external hazards) unless it can be shown that the contribution from specific hazard groups does not affect the decision."

Section 6.1.5.8 in LAR Attachment 6 states, "[f]or both CNS and MNS, the remaining external hazards would not be impacted by the 14 day CT completion time" (i.e., hazards other than those modelled in the PRAs). The LAR does not explain how it is concluded that the risk associated with the EDG 14-day CT is not impacted by other external hazards. Provide the results of a systemic assessment of other external hazards (such as those listed in Appendix 6-A of Part 6 of the PRA Standard ASME/ANS RA-Sa-2009) demonstrating that the LAR is not impacted by other external hazards.

Duke Energy Response to APLA RAI-09:

The McGuire site was extensively assessed against external hazards during the IPEEE evaluation. Table 1 presents the initial external event listing given in the 1994 IPEEE submittal reports for both CNS and MNS sites. Table 2 provides the screening justification for the majority of these events.

The remaining events were addressed in detail in the IPEEE submittal. Besides seismic, fire, high winds and flooding, McGuire also analyzed aircraft crashes, transportation events, impact of nearby military and industrial facilities, on-site storage of toxic materials, on-site storage of explosive materials and gas pipeline ruptures. Since the screening criteria found in SPR EXT-B1 of Section 6 in the ASME / ANS RA-Sa-2009 Standard is essentially the same as that used in the IPEEE submittal, none of these hazards are deemed to be significant contributors to plant risk.

Since the IPEEE response was submitted, updated fire and high winds analyses have been developed and peer-reviewed against the ASME / ANS RA-Sa-2009 Standard. Furthermore, as part of the Fukushima NTTF 2.1 response, external flooding concerns for McGuire were addressed via updated analyses and mitigating strategies. The sites were evaluated for flooding from the following sources:

- Local Intense Precipitation
- Flooding in Reservoirs
- Dam Failures
- Storm Surge and Seiche
- Tsunami
- Ice-Induced Flooding
- Channel Diversion
- Combined Effects

The results of these analyses demonstrate that McGuire external flooding events meet their licensing design basis for local intense precipitation and thus screen out per Section 6, SPR EXT-B1 of the ASME / ANS RA-Sa-2009 Standard.

Table 1

McGuire and Catawba Preliminary External Initiating Events List

1.	Aircraft	20.	Low Lake or River Water Level
2.	Avalanche	21.	Low Winter Temperature
3.	Coastal Erosion	22.	Meteorite
4.	Drought	23.	Pipeline Accident (gas, etc.)
5.	External Flooding	24.	Intense Precipitation
6.	Extreme Winds and Tornadoes	25.	Release of Chemicals in On-site Storage
7.	Fire	26.	River Diversion
8.	Fog	27.	Sandstorm
9.	Forest Fire	28.	Seiche
10.	Frost	29.	Seismic Activity
11.	Hail	30.	Snow
12.	High Tide, High Lake Level, or High River Stage	31.	Soil Shrink-Well Consolidation
13.	High Summer Temperature	32.	Storm Surge
14.	Hurricane	33.	Transportation Accidents
15.	Ice Cover	34.	Tsunami
16.	Industrial or Military Facility Accident	35.	Toxic Gases
17.	Internal flooding	36.	Turbine-Generated Missile
18.	Landslide	37.	Volcanic Activity
19.	Lightning	38.	Waves

Table 2

McGuire Screening Justifications for Other External Initiating Events

	Event	Remarks
1	Avalanche	There are no mountains in the vicinity of McGuire from which a significant avalanche could be generated.
2	Coastal Erosion	McGuire is located more than 150 miles from the nearest coastal area. However, to protect the lake edge from erosion, the yard areas subjected to waves are protected by riprap underlain by a thick subgrade of filter material. Therefore, lake edge erosion will not be a significant problem.
3	Drought, High Summer Temps., Low Lake or River Water Level	The effect of a drought, high summer temperatures, low lake level, or low river water level at McGuire is insignificant because there are upstream dams that provide water level control on Lake Norman.
4	Fog	Accident data involving surface vehicles or aircraft would include the effects of fog.
5	Forest Fire	Bush and local forest fires are handled by the local fire department. Such fires are not considered to have any impact on the station because the site is cleared and the fire cannot propagate to station buildings or equipment
6	Frost, Hail, Snow, Ice Cover	Both the Reactor Building and the Auxiliary Building are designed for a combination of snow, ice, and rain. Low winter temperatures causing failure of instruments is included in the plant trip frequency data.
7	Hurricane	[Hurricanes are handled under the high winds analysis.] The effect of water from a hurricane is considered similar to the effect of intense precipitation.
8	Landslide	Landslides are considered an insignificant hazard at McGuire. The Standby Nuclear Service Water Pond (SNSWP) dam is the only natural or man-made slope which, upon failure, would prevent safe shutdown of the plant. Therefore, the SNSWP was statically designed for stability under all loading conditions.
9	Lightning	The most probable effect of lightning is the loss of off-site power due to a strike in the switchyard. These occurrences are accounted for in the loss of off-site power initiating event frequency.
10	Meteorite	This event has significantly lower frequency than other events with similar uncertainties. The

	Event	Remarks
		occurrence of a meteorite event could not result in worse consequences than other external events of a higher frequency. Therefore, this event is excluded because it will not significantly influence the total risk.
11	Intense Precipitation	Per response to NTTF 2.1, McGuire meets its licensing basis for local intense precipitation and thus screens out per Section 6, SPR EXT-B1 of the ASME / ANS Standard.
12	River Diversion	No present means exist to divert or reroute the river flow through the dams other than insignificant amounts of water used for municipal supply.
13	Sandstorm	McGuire is located more than 150 miles from the nearest area with a large sand deposit. The likelihood of occurrence is insignificant
14	Seiche	Since the flood examined in the [U]FSAR uses the largest rate and volume (for external sources), this analysis provides a reasonable estimate of the effects of all TB flooding events.
15	Soil Shrink-Well Consolidation	Per the McGuire [U]FSAR, hazards associated with soil shrink-well consolidation will be insignificant
16	Storm Surge	Since the flood examined in the [U]FSAR uses the largest rate and volume (for external sources), this analysis provides a reasonable estimate of the effects of all TB flooding events.
17	Tsunami	McGuire is located more than 150 miles from the nearest coastal area at an elevation of 760 ft. mean sea level. Therefore, tsunami effects are insignificant.
18	Turbine-Generated Missile	The majority of the structures at McGuire are located either along or within close proximity to the longitudinal centerlines of the respective turbines. Calculations on turbine missiles prepared for the McGuire [U]FSAR indicate that the contribution to plant risk from the turbines would be insignificant
19	Volcanic Activity	No active volcanoes exist within the vicinity of McGuire.
20	Waves	Since the flood examined in the [U]FSAR uses the largest rate and volume (for external sources), this analysis provides a reasonable estimate of the effects of all TB flooding events.

APLA RAI-10 – Avoiding Plant Configurations that Contribute to Significant Risk

Section 2.3 of RG 1.177, Revision 1, cites the need to avoid risk-significant plant configurations and discusses Tier 2 of a three-tiered approach for evaluating risk associated with proposed TS CT changes. According to Tier 2, the licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is out of service consistent with the proposed TS change. Once the specific plant equipment are identified, an assessment can be made as whether certain enhancements to the TS or procedures are needed to avoid risk-significant plant configurations. In addition, Section 2.4 of RG 1.177 states, as part of the TS acceptance guidelines specific to permanent CT changes, the licensee should demonstrate that there are appropriate restrictions on dominant risk-significant configurations associated with the change.

Based on LAR Tables 3 and 4 for CNS and MNS, respectively, the margin between the calculated ICCDP and ICLERP results and the risk acceptance guidelines in RG 1.177 is small. Therefore, it is important that plant configurations contributing to risk be avoided when the EDGs are taken out of service. Section 3.12.2 of the LAR provides a discussion of Tier 2 ("Avoidance of Risk-Significant Plant Configurations") and identifies in LAR Tables 1 and 2 those SSCs for both CNS and MNS that are important to the 14 day EDG CT based on SSC risk importance values presented in LAR Attachment 7. LAR Section 3.12.2 states that unavailability of the identified SSCs should be avoided during the CT. However, the LAR does not describe a mechanism or a set of controls that will be used by the plants to avoid the unavailability of these SSCs.

To address the observations above, explain how the unavailability of SSCs identified in LAR Tables 1 and 2 (which represent high risk configurations for CNS and MNS) will be avoided during the 14 day EDG CT. Include explanation of the mechanism that ensures high risk configurations will be avoided.

Duke Energy Response to APLA RAI-10:

Duke Energy relies on several methods to limit work on high risk configurations. These methods consists of Technical Specifications (Tech Specs) and Selected Licensee Commitments (SLC), Cycle Schedule, Protected Equipment schemes, and the Electronic Risk Assessment Tool (ERAT.)

Tech Specs and SLC specify requirements for structures, systems or components (SSC) to be operable or functional. Tech Specs and SLC specify an allow outage time (AOT) for SSCs. Generally, when multiple trains are out of service, the AOT is very short or a shutdown is required.

Duke Energy's online work management practices are described in AD-WC-ALL-0200 (On-Line Work Management.) A key provision of this practice is the use of a Cycle Schedule. "Plant systems are grouped in a rotating cycle of Work Weeks. System groupings are based on Technical Specification requirements, Probabilistic Risk Assessment (PRA) and resource loading." Work on EDG requiring entry into the extended AOT will be scheduled for the work week associated with the EDG's respective train. Work on the opposite train and work on key equipment (e.g., SSF and TDCA pump) will not be scheduled during this time period.

Protected equipment plans have been developed for important SSCs. These plans are maintained by the Operations group. AD-OP-ALL-0201 provides guidance for the management of protected equipment. Protected equipment plans have been developed for the EDGs. As an example, the MNS EDG Protected Equipment Plan specifies the following:

- Unit Related Relay House Area
- Unit Related Switchyard Busline Area
- Unit Related Main Transformer Yard
- SSF
- Normal Incoming Breaker for 4160 Bus
- Opposite Train's 4160 Switchgear Room
- Opposite Train's RN Pump (pump area)
- Unit Related 6900V Switchgear Room
- Opposite Train's EDG Room

For entry into the extended AOT, this list will be updated to include the diesel driven Instrument Air compressors "G" and "H."

Work on those SSCs which is not prohibited by Tech Specs or SLC, the Cycle Schedule, or the Protected Equipment Plan will be managed using the Electronic Risk Assessment Tool. The ERAT calculates the CDF and LERF for equipment out of service. The tool displays the risk as one of four colors - Green (lowest), Yellow, Orange, or Red (highest.) Colors above Green represent a configuration where the ICCDP (ICLERP) could exceed 1.0E-06 (1.0E-07) within 7 days. Colors above Green receive extra review, consideration of risk management plans, and consideration of rescheduling to remove or reduce the color.

APLA RAI-12 – Implementation Verification of ESPS System

Regulatory Guide 1.174, Revision 2, provides quantitative guidelines on CDF, LERF, and identifies acceptable changes to these frequencies that result from proposed changes to the plant's licensing basis and describes a general framework to determine the acceptability of risk-informed changes. The NRC staff's review of the information in the LAR has identified additional information that is required to fully characterize the risk estimates.

The estimated risk associated with the EDG CT extension is based on assumptions about an ESPS system that has not yet been installed and operator actions for which procedures have not been completed. Upon completion of these plant modifications and procedures, the PRA models will need to be assessed against the as-built, as-operated plant and updated, as necessary. Then new risk estimates will need to generated and evaluated to confirm that the conclusions of the LAR have not changed. Some examples of items that require future evaluation and/or confirmation include:

• When each site's ESPS-related procedures are finalized, the HRA will need to be reviewed and revised, as necessary, to reflect the as-built, as-operated plant. This may include the need to perform new walk-throughs, operator interviews, timing analyses, determination of other Performance Shaping Factors, and updated dependency analyses.

• When the ESPS hardware (including instrument and power cabling) is installed, the fault tree models will need to be reviewed for consistency with the as-built configuration.

• ESPS cable routing, capabilities, flood heights, and other geospatial design information will need to be reviewed and confirmed unchanged for the fire and internal flooding analyses.

• With regard to fire F&Os CNS CS-B1-01 and MNS CS-C4-01, the newly installed ESPS equipment will need to be evaluated for proper overcurrent protection and coordination.

To address the above observations, propose a license condition requiring that after the ESPS system is installed (and applicable procedures updated) and prior to implementing the 14-day EDG CT, the PRAs for the hazards evaluated in this risk assessment will be updated, as necessary, to reflect the as-built, as-operated plant. The risk results in the LAR will be updated, as necessary, and compared with the risk acceptance guidelines in RG 1.177 and RG 1.174 to confirm the conclusions of the LAR. Also, include a plan of action if RG 1.177 and RG 1.174 risk acceptance guidelines are exceeded.

Duke Energy Response to APLA RAI-12:

As part of modification close-out and Tech. Spec. change implementation, action assignments have been created to ensure that upon completion of the ESPS plant modifications and associated procedures, the PRA models will be assessed against the as-built, as-operated plant and updated, as necessary. New risk estimates will be generated as needed and evaluated to confirm that the conclusions of the LAR have not changed.

The assignments include:

• When each site's ESPS-related procedures are finalized, review and revise the HRA, as necessary, to reflect the as-built, as-operated plant. This may include the need to perform new walk-throughs, operator interviews, timing analyses, determination of other Performance Shaping Factors, and updated dependency analyses. If HRA changes are needed, make the changes and inform those tasked with updating the hazard models.

• Following installation of the ESPS system and origination of the associated plant documentation, review the internal events model analysis to ensure that assumptions and inputs match the as-built, as-operated plant. Ensure the ESPS hardware (including capability, instrument and power cabling) is consistent with the ESPS model. If model changes are needed, make the changes and inform those tasked with updating the other hazard models. Update the analysis and risk estimates to reflect changes as necessary.

• Following installation of the ESPS system and origination of the associated plant documentation, review the internal flood model analysis to ensure that assumptions and inputs match the as-built, as-operated plant. Review flood heights and other geospatial design information for impact on the analysis. Update the analysis and risk estimates to reflect changes as necessary.

• Following installation of the ESPS system and origination of the associated plant documentation, review the high winds model analysis to ensure that assumptions and inputs match the as-built, as-operated plant. Update the analysis and risk estimates to reflect changes as necessary.

• Following installation of the ESPS system and origination of the associated plant documentation, review the fire model analysis to ensure that assumptions and inputs match the as-built, as-operated plant. Some examples of items that require future evaluation and/or confirmation include: 1. Review ESPS cable routing and other geospatial design information. 2. With regard to fire F&Os MNS CS-C4-01, evaluate the newly installed ESPS equipment for proper overcurrent protection and coordination. Update the analysis and risk estimates to reflect changes as necessary.

• Following installation of the ESPS system and origination of the associated plant documentation, review the seismic model analysis to ensure that assumptions and inputs match the as-built, as-operated plant. Update the analysis and risk estimates to reflect changes as necessary.

• Revise the LAR PRA calculations to reflect any changes to the analysis from the previous tasks.

• Update the LAR risk results and sensitivity studies, as necessary, and compare with the risk acceptance guidelines in RG 1.177 and RG 1.174 to confirm the conclusions of the LAR. If the updated risk estimates (including sensitivity studies) do not meet the risk acceptance guidelines of RG 1.174 and RG 1.177, then the NRC will be notified and additional analytical efforts, and/or procedure changes, and/or plant modifications will be made to assure the RG 1.174 and RG 1.177 risk acceptance criteria are met.

APLA RAI-13 – Updated Internal Events Logic Transferred to Other Hazard Models

The LAR states that the proposed change to the TS completion time has been developed using the risk-informed processes described in RG 1.174, Revision 2, and RG 1.177, Revision 1. Based on Section 2.3.1 of RG 1.177, the technical adequacy of the PRA must be compatible with the safety implications of the Technical Specification change being requested and the role that the PRA plays in justifying that change. The RG 1.177 endorses the guidance provided in RG 1.200, Revision 2, on PRA technical adequacy. The RG 1.200 describes a peer review process utilizing ASME/ANS RA-Sa-2009 as one acceptable approach for determining the technical adequacy of the PRA once acceptable consensus approaches or models have been established for evaluations that could influence the regulatory decision.

Section 6.1.3.1 of LAR Attachment 6 states that peer reviews were performed for both CNS and MNS internal events PRAs in 2015. For MNS, it is stated that resolution of 64 F&Os were implemented and approved by an Independent Review in 2016. For CNS, it is not clear to what extent the internal events PRA was updated in response to F&Os. It is generally understood that the mitigation logic (particularly system modeling) from the internal events PRA model is used as the basis for other PRA hazard models. The LAR indicates that the peer reviews for the high winds PRAs for CNS and MNS were performed in August 2013 and October 2014, respectively. Also, the LAR indicates that the peer reviews for CNS and MNS fire PRAs were performed in July 2010 and September 2009, respectively. Accordingly, it is not clear how the CNS and MNS fire and high winds PRAs incorporate updates performed for the internal events PRAs needed to align with the PRA quality expectations prescribed in RG 1.200, Revision 2. It is also not clear, given that the high winds and fire PRAs were already peer reviewed, what prompted the need for a peer review of the internal events PRAs (e.g., incorporation of new methodologies or changes in PRA scope/capability that impacted the significant accident sequences). To address the above observations, provide the following information.

APLA RAI-13.a

Explain what prompted the need for a peer review of the CNS and MNS internal events PRAs. Include explanation of whether significant changes had been made in the CNS and MNS internal event PRAs such as important equipment modifications or model upgrade since the last time the PRAs had been peer reviewed.

Duke Energy Response to APLA RAI-13.a:

The MNS internal events PRA was originally peer reviewed in 2000, using the technical element checklists contained in NEI 00-02, Industry PRA Peer Review Process Guidelines. After the Findings from the peer review were addressed, the decision was made to have the PRA peer reviewed to RG 1.200 and the ASME/ANS PRA Standard, since the model was significantly upgraded. The old F&Os would not need to be revisited as part of a PRA quality review, thereby eliminating unnecessary work.

The McGuire fire PRA model is based on the Rev. 3 PRA model. The internal events, internal flood, and high wind models have all been updated to Rev. 4. Significant internal events model changes between revisions 3 and 4 include the following:

- Updated model data
- Re-performed HRA and dependency analysis
- Added and deleted initiators
- Incorporated the modification to install a 2-inch orifice between valves 1WL321A and 1WL322B, thereby eliminating a LERF flowpath through these valves
- Switched from the Multiple Greek Letter approach to the alpha-factor method for quantifying common cause failure events (model upgrade).

APLA RAI-13.b

Explain how the CNS and MNS fire and high winds PRAs incorporate updates performed for the internal events PRA in response to F&Os generated from the 2015 peer reviews.

Duke Energy Response to APLA RAI-13.b:

These models have not been revised to incorporate updates from the 2015 peer reviews.

APLA RAI-13.c

If the CNS and MNS fire and high winds PRAs do not incorporate updates performed for the internal events PRAs in response to F&Os generated from the 2015 peer reviews, then justify that the CNS and MNS fire and high winds PRAs meets PRA quality expectations prescribed in RG 1.200, Revision 2, for risk-informed applications. Alternatively, incorporate updates performed for the internal events PRAs in response to F&Os generated from the 2015 peer reviews into the CNS and MNS fire and high winds PRA models used for this LAR that aggregate the PRA updates requested in APLA RAI-14.

Duke Energy Response to APLA RAI-13.c:

The acceptability of the fire and high wind models for the ESPS LAR is justified by the peer reviews on those models (see Section 6.1.3.1 of LAR Attachment 6) and the resolutions of Finding F&Os generated during those reviews, as discussed in Attachment 8, section 8.8 (McGuire High Winds) and section 8.10 (McGuire Fire). In addition, for ESPS, the MNS fire PRA model was updated to incorporate the latest fire modeling information used for the NFPA 805 RAI #3 submittal.

The fire and high wind models are based on minor revisions of the Rev. 3 internal events model, as noted in the response to RAI 13.a above. The 2015 peer reviews were performed on the Rev. 4 internal events models, which are significantly different from the Rev. 3 models. Thus, F&Os generated from the 2015 peer reviews are not necessarily applicable to the fire and high wind models.

APLA RAI-14 – Aggregate Update Analysis

Regulatory Guide 1.174, Revision 2, provides quantitative guidelines on CDF and LERF and identifies acceptable changes to these frequencies that result from proposed changes to the plant's licensing basis and describes a general framework to determine the acceptability of risk-informed changes. Regulatory Guide 1.177, Revision 1, provides risk acceptance guidelines on ICCDP and ICLERP and identifies acceptable changes to these probabilities that result from proposed changes to permanent changes to the licensee's TSs. The NRC staff review of the information in the LAR has identified additional information that is required to fully characterize the risk estimates.

The PRA methods and treatments discussed in the following RAIs may need to be revised to be acceptable by the NRC:

• APLA RAI-02.b regarding not modeling alternate alignments in the MNS PRAs.

• APLA RAI-05.a regarding use of appropriate EDG, SSF, and ESPS failure probabilities in the CNS and MNS PRAs.

• APLA RAI-05.b regarding use of appropriate non-safety equipment failure probabilities for the SSF and ESPS diesel generators in the CNS and MNS PRAs.

• APLA RAI-06.a regarding consistent application of HEP values for ESPS in the CNS and MNS PRAs.

• APLA RAI-06.b regarding incorrect ESPS HEPs in the CNS and MNS PRAs.

• APLA RAI-07.b regarding the reasonableness of the ESPS HFEs and HEPs in the CNS and MNS PRAs.

• APLA RAI-13.c regarding incorporation of internal events PRA modeling updates in response to F&O into the CNS and MNS fire and high winds PRA models.

To fully address the RAIs cited above, provide the following:

APLA RAI-14.a

For PRA updates required in response to the RAIs cited above, provide the results of an aggregate analysis that reflect the combined impact of the updates on the LAR risk results (i.e., ΔCDF, ΔLERF, ICCDP and ICLERP). PRA updates that cannot have a synergistic impact with other updates can be performed one-at-a-time. Also, provide an update of the sensitivity studies (e.g., the sensitivity study referred to in RAI 04) discussed in the LAR that reflect the combined updates to the PRA performed in response to other RAIs that support the LAR risk results.

Duke Energy Response to APLA RAI-14.a:

The 14 day CT aggregate sensitivity case results are shown below. The results are below the 1E-6 ICCDP and 1E-7 ICLERP RG 1.177 guidelines.

RG 1.177 ICCDP Summary

Hazard	14 Day CT	Base	Multiplier	ICCDP
Internal Events	3.55E-06	3.29E-06	14/365	9.97E-09
Internal Flooding	9.43E-06	7.74E-06	14/365	6.48E-08
High Winds	2.30E-05	9.04E-06	14/365	5.35E-07
Fire (limiting Unit)	5.79E-05	5.22E-05	14/365	2.19E-07
Seismic	6.68E-07	5.31E-08	14/365	2.36E-08
			Sum =	8.52E-07

RG 1.177 ICLERP Summary

Hazard	14 Day CT	Base	Multiplier	ICLERP
Internal Events	5.33E-07	4.78E-07	14/365	2.11E-09
Internal Flooding	5.99E-07	3.46E-07	14/365	9.70E-09
High Winds	2.04E-06	8.32E-07	14/365	4.63E-08
Fire (limiting Unit)	6.00E-06	5.55E-06	14/365	1.73E-08
Seismic	2.68E-07	2.18E-08	14/365	9.44E-09
			Sum =	8.49E-08

The overall CDF and LERF impact of the AOT and addition of the ESPS system still represents a risk decrease. (The values presented include the conservatism and changes required for the aggregate risk calculation).

Since the seismic modeling does not credit the ESPS system, the ESPS credit and the base case models and values are the same.

351 Day ICCDP Risk Contribution Summary

Hazard	ESPS credit	Base	Multiplier	ICCDP
Internal Events	3.13E-06	3.29E-06	351/365	-1.54E-07
Internal Flooding	7.72E-06	7.74E-06	351/365	-1.92E-08
High Winds	5.51E-06	9.04E-06	351/365	-3.39E-06
Fire (limiting Unit)	5.17E-05	5.22E-05	351/365	-4.81E-07
Seismic	5.31E-08	5.31E-08	351/365	0.00E+00
			Sum =	-3.95E-06

351 Day ICLERP Risk Contribution Summary

Hazard	ESPS credit	Base	Multiplier	ICLERP
Internal Events	4.52E-07	4.78E-07	351/365	-2.50E-08
Internal Flooding	3.39E-07	3.46E-07	351/365	-6.73E-09
High Winds	4.46E-07	8.32E-07	351/365	-3.71E-07
Fire (limiting Unit)	5.49E-06	5.55E-06	351/365	-5.77E-08
Seismic	2.18E-08	2.18E-08	351/365	0.00E+00
			Sum =	-4.41E-07

Total risk result from assuming a 14 day CT entry and ESPS nominal availability the remainder of the year.

Δ CDF For Entire Change

Hazard	14 day CT	351 Day	Δ CDF
Internal Events	9.97E-09	-1.54E-07	-1.44E-07
Internal Flooding	6.48E-08	-1.92E-08	4.56E-08
High Winds	5.35E-07	-3.39E-06	-2.86E-06
Fire (limiting Unit)	2.19E-07	-4.81E-07	-2.62E-07
Seismic	2.36E-08	0.00E+00	2.36E-08
		Sum =	-3.16E-06

Δ LERF For Entire Change

Hazard	14 day CT	351 Day	Δ LERF
Internal Events	2.11E-09	-2.50E-08	-2.29E-08
Internal Flooding	9.70E-09	-6.73E-09	2.97E-09
High Winds	4.63E-08	-3.71E-07	-3.25E-07
Fire (limiting Unit)	1.73E-08	-5.77E-08	-4.04E-08
Seismic	9.44E-09	0.00E+00	9.44E-09
		Sum =	-3.57E-07

APLA RAI-14.b

For each RAI listed above, summarize briefly how the issue(s) cited in the RAI were resolved for the PRA or LAR. If the resolution involved an update to the PRA models, then briefly summarize the PRA update.

Duke Energy Response to APLA RAI-14.b:

• APLA RAI-02.b:
The response to APLA-RAI-02.b describes the resolution. There is no update to the PRA models required.

• APLA RAI-05.a:
To address the issue the latest plant specific failure rates for the already installed diesels were used. The ESPS failure rate used the generic station blackout diesel failure rates from NUREG/CR-6928 2016 updated parameter estimates. These values were used for the aggregate sensitivity case.

• APLA RAI-05.b
The ESPS failure rate used the generic station blackout diesel failure rates from NUREG/CR-6928 2016 updated parameter estimates. These values were used for the aggregate sensitivity case. Explanation of SSF failure rate development provided in APLA RAI-05.b response.

• APLA RAI-06.a
The appropriate case specific HEP values were used. The aggregate sensitivity case doubled these values.

• APLA RAI-06.b
The appropriate case specific HEP values were used. The aggregate sensitivity case doubled these values.

• APLA RAI-07.b
The estimated HEP values have been doubled for the aggregated case.

• APLA RAI-13.c
The models used, were as described and justified in the response to APLA RAI-13.c.

APLA RAI-14.c

Confirm that the updated results still meet the risk acceptance guidelines in RG 1.177, Revision 1, and RG 1.174, Revision 2.

Duke Energy Response to APLA RAI-14.c:

Results presented in part a show the 14 day CT ICCDP and ICLERP are within the RG 1.177 guidelines and the overall risk reduction is within the limits of RG 1.174.

APLA RAI-14.d

If the risk acceptance guidelines are exceeded, then identify which risk acceptance guidelines are exceeded and provide qualitative or quantitative justification that support the conclusions of the LAR. If applicable, include discussion of conservatisms in the analysis and the risk significance of these conservatisms.

Duke Energy Response to APLA RAI-14.d:

The risk acceptance guidelines were not exceeded. The only equipment test & maintenance explicitly excluded from the 14 day CT aggregated risk sensitivity case were the ESPS system and the opposite train diesel generators.

APLA RAI-15 – LAR Anomalies

Section 4, "Element 4: Documentation and Submittal," of RG 1.177, Revision 1, states that the evaluations performed to justify the proposed TS changes should be documented and included in the LAR submittal. Address the following clerical oversights in the LAR.

APLA RAI-15.a

The LAR states as a reference RG 1.200, but does not provide a revision.

Clarify what revision is being referenced in the LAR and ensure other LAR references have the appropriate revision or date.

Duke Energy Response to APLA RAI-15.a:

Attachment 6, Section 6.3, Reference 2, Regulatory Guide 1.200 is Revision 2.

APLA RAI-15.c

Attachment 7 of the LAR lists that there are 648 pages, but only 646 were provided.

Clarify the number of pages in LAR Attachment 7 and provide any missing pages.

Duke Energy Response to APLA RAI-15.c:

There are no missing pages in the LAR. Attachment 7 should say out of 646 pages.

APLA RAI-15.d

Table 6-25 of the LAR lists the results as CDF(/yr) and LERF(/yr), yet the values in the first two rows of those columns appear to be ICCDP and ICLERP.

Clarify the correct column labeling for this table in the LAR.

Duke Energy Response to APLA RAI-15.d:

Table 6-25 is correct as labeled. It is a combination of the same units of information that Table 6-23 and 6-24 presents, combined into one table. The first 4 entries could have extra labels for identifying ICCDP and ICLERP if it were determined necessary.

APLA RAI-15.f

Section 3.12.1 of the LAR lists four PRA assumptions, while LAR Attachment 6, Section 6.1.6 lists five PRA assumptions.

Clarify the correct number of PRA assumptions used in the analysis.

Duke Energy Response to APLA RAI-15.f:

Section 3.12.1 of the LAR is incorrect. Five PRA assumptions were used in the analysis, as listed in Attachment 6.

Attachment 4

Regulatory Commitments

The following table identifies the regulatory commitments in this document by Duke Energy Carolinas, LLC (Duke Energy) for the McGuire Nuclear Station, Units 1 and 2. Any other statements in this submittal represent intended or planned actions, and are provided for information purposes. They are not considered to be regulatory commitments.

COMMITMENT	TYPE		SCHEDULED COMPLETION DATE
	One-time	Continuing Compliance	
1. The preplanned diesel generator (DG) maintenance will not be scheduled if severe weather conditions are anticipated. Weather conditions will be evaluated prior to intentionally entering the extended DG Completion Time (CT) and will not be entered if official weather forecasts are predicting severe weather conditions (i.e., thunderstorm, tornado or hurricane warnings). Operators will monitor weather forecasts each shift during the extended DG CT. If severe weather or grid instability is expected after a DG outage begins, station managers will assess the conditions and determine the best course for returning the DG to operable status.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
2. Component testing or maintenance of safety systems and important non-safety equipment in the offsite power systems that can increase the likelihood of a plant transient (unit trip) or loss of offsite power (LOOP) will be avoided during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.

3. No discretionary switchyard maintenance will be performed during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
4. The turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities during the extended CT. The turbine-driven auxiliary feed water pump will be controlled as "protected equipment" during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
5. During the extended DG CT, the Emergency Supplemental Power Source (ESPS) will be routinely monitored during operator rounds, with monitoring criteria identified in the operator rounds. The ESPS will be monitored for fire hazards during operator rounds.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.

6. Licensed Operators and Auxiliary Operators will be trained on the purpose and use of the ESPS and the revised emergency procedure (EP) actions. Personnel performing maintenance on the ESPS will be trained.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
7. The system load dispatcher will be contacted once per day to ensure no significant grid perturbations (high grid loading unable to withstand a single contingency of line or generation outage) are expected during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
8. TS required systems, subsystems, trains, components and devices that depend on the remaining power sources will be verified to be operable and positive measures will be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
9. Prior to entering the extended CT for an inoperable DG, the station will ensure that each train of shared systems is powered by an operable Class 1E AC Distribution System, with an operable DG, from opposite units.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.