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RS-18-149

10 CFR 50.90

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

Byron Station, Units 1 and 2
Renewed Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

Subject: Supplemental Information Related to License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

References:

1. Letter from D. M. Gullott (Exelon Generation Company, LLC (EGC)) to U.S. NRC, "License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2," dated August 10, 2018
2. Letter from J. S. Wiebe (NRC) to B. C. Hanson (EGC), "Byron Station, Unit Nos. 1 and 2 - Supplemental Information Needed for Acceptance of Requested Licensing Action Re: One-Time Extension of Technical Specification 3.8.1, 'AC Sources-Operating,' A2 Completion Time (EPID L-2018-LLA-0218)," dated December 12, 2018

In Reference 1, Exelon Generation Company, LLC (EGC) requested an amendment to Facility Operating License (FOL) Nos. NPF-37 and NPF-66 for Byron Station, Units 1 and 2. The proposed change to the Byron Station, Units 1 and 2 Technical Specifications (TS) is intended to serve as a contingency to allow the restoration of an inoperable qualified circuit between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System resulting from an unanticipated failure of Unit 2 System Auxiliary Transformer (SAT) 242-1.

In Reference 2, the NRC requested supplemental information required to complete its review of Reference 1. EGC agreed that this information must be provided by December 27, 2018.

EGC has reviewed the information supporting a finding of no significant hazards consideration, and the environmental consideration, that were previously provided to the NRC in the Reference 1. The supplemental information provided in this letter does not affect the bases for concluding that the proposed license amendment does not involve a significant hazards consideration. In addition, the information provided in this submittal does not affect the bases for concluding that neither an environmental impact statement nor an environmental assessment needs to be prepared in connection with the proposed amendment.

EGC is providing the requested information, as described in Reference 2, in the Attachments to this letter.

This submittal is subdivided as follows:

Attachment 1 provides the supplemental information requested by the NRC in Reference 2.

Attachment 2 includes an update to the marked-up TS page with the proposed changes indicated.

Attachment 3 includes the revised (clean copy) of the TS page.

Attachment 4 is an updated Unit 2 System Auxiliary Transformer 242-2 Repair and Testing Schedule.

EGC continues to request approval of the proposed license amendment request by August 10, 2019. Once approved, the amendments will be implemented immediately.

EGC is notifying the State of Illinois of this supplement to the application for a change to the TS by sending a copy of this letter and its attachments to the designated State Official in accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b).

There are no regulatory commitments contained within this letter.

If you have any questions concerning this letter, please contact Mr. Mitchel A. Mathews at (630) 657-2819.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 21st day of December 2018.

Respectfully,

David M. Gullott
Director – Licensing and Regulatory Affairs
Exelon Generation Company, LLC

Attachments:

1. Supplemental Information Related to License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2
2. Updated Proposed Technical Specifications Page Changes (Markups)
3. Updated Revised (Clean) Technical Specifications Page
4. Updated Unit 2 System Auxiliary Transformer 242-2 Repair and Testing Schedule

cc: NRC Regional Administrator, Region III
NRC Senior Resident Inspector, Byron Station
Illinois Emergency Management Agency – Division of Nuclear Safety

ATTACHMENT 1
Supplemental Information Related to License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

SUPPLEMENTAL INFORMATION NEEDED

AMENDMENT REQUEST REGARDING ONE-TIME EXTENSION OF

TECHNICAL SPECIFICATION 3.8.1, "AC SOURCES-OPERATING," A.2 COMPLETION TIME

EXELON GENERATION COMPANY. LLC

BYRON STATION, UNIT NOS. 1 AND 2

DOCKET NOS. 50-454 AND 50-455

By letter dated August 10, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML18226A097), Exelon Generation Company, LLC (the licensee) submitted a license amendment request for the Byron Station, Unit Nos. 1 and 2. The proposed amendments would authorize a one-time extension of Technical Specification (TS) 3.8.1, "AC [Alternating Current] Sources-Operating," A.2 completion time (CT).

Consistent with Section 50.90 of Title 10 of the Code of Federal Regulations (10 CFR), an amendment to the license (including the TSs) must fully describe the changes requested, and following, as far as applicable, the form prescribed for original applications. Section 50.34 of 10 CFR addresses the content of technical information required. This section stipulates that the submittal address the design and operating characteristics, unusual or novel design features, and principal safety considerations.

A public meeting was held on November 6, 2018 (ADAMS Accession No. ML18305B403), per meeting notice dated November 1, 2018 (ADAMS Accession No. ML18305B403), to discuss U.S. Nuclear Regulatory Commission (NRC or the Commission) staff questions regarding the amendment request. Based on the results of the public meeting and the NRC staff's initial review of your application, the staff concluded that the information identified below is necessary to enable the staff to make an independent assessment regarding the acceptability of the proposed amendment request in terms of regulatory requirements and the protection of public health and safety and the environment.

The NRC staff requests the following information in order to complete its detailed review:

NRC Question:

1. *In its letter dated August 10, 2018, the licensee proposed the addition of a note to TS 3.8.1, Required Action A.2, CT, as follows:*

   > *For the failure of Unit 2 System Auxiliary Transformer 242-1, restore the required qualified circuit to OPERABLE status within 79 days.*

   The note does not contain an expiration date for the extended CT or link the extended CT to a specific failure date of System Auxiliary Transformer (SAT) 242-2. Therefore, the proposed TS revision would not limit the extended CT to a one-time, temporary *extension associated with the SAT 242-2 failure addressed in the license amendment request.*

The NRC staff requests that the application be supplemented to provide an expiration date or to link the extended CT to a specific failure date of SAT 242-2

Exelon Generation Company, LLC (EGC) Response

An updated proposed Technical Specifications (TS) page markup and an updated revised TS page proposing a 60-day Completion Time in lieu of 79 days for Technical Specification 3.8.1, Required Action A.2 have been provided in Attachments 2 and 3, respectively.

NRC Question:

2. *In its letter dated August 10, 2018, the licensee states:*

> *In addition, the PRA [probability risk assessment] Model of Record includes an assumption that a unit-to-unit crosstie of the ESF [engineered safety feature] buses will be in place if both parts of the Unit 2 SAT are out-of- service (242-1 and 242-2). Since the proposed configuration does not implement the unit-to-unit crosstie, the PRA model is modified to remove that assumption by setting some gates to FALSE or by inserting logic to require the unit-crosstie alignment if necessary.*

The NRC staff's understanding is that the risk analysis associated with the proposed 79-day allowed outage time does not include consideration of the maintenance and operator actions required to implement the unit-to-unit crossties. However, the proposed 79-day allowed outage time appears to begin when the 242-1 SAT fails with the existing current condition of the out-of-service 242-2 SAT.

In the current configuration, should SAT 242-1 become inoperable, Emergency Diesel Generator (EDG)-2A and EDG-2B will be the immediate sources of power to 4.16 Kilovolt (kV) ESF buses 241 and 242, respectively. In its letter dated August 10, 2018, the licensee proposes to realign the two 4.16kV safety buses from EDGs to the Unit No. 2 unit auxiliary transformers. However, this realignment requires additional operator actions at transformers and circuit breakers that were not considered in the licensee's letter dated August 10, 2018, for the risk assessment. The NRC staff notes that there are human error probabilities associated with operator actions to realign the two 4.16kV ESF buses, and these human error probabilities may significantly impact the risk.

Regulatory Guide (RG) 1.177, Revision 1, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated May 2011 (ADAMS Accession No. ML100910008), Section A-1.3.1.1, states, in part:

> *If other components are reconfigured while the component is down, these reconfigurations can be incorporated in estimating R_1 or ΔR, using the*

> > *PRA. If other components are tested before repair or if maintenance is carried out on the downed components, the conduct of these tests and their outcomes also can be modeled.*

> *Therefore, it appears that the risk associated with operator reconfiguration should be included in the risk assessment. The NRC staff requests the application be supplemented as follows:*

> > *1. Provide an explanation of how the risk associated with the actions to realign the two 4.16kV safety buses from the EDGs to the Unit No. 2 auxiliary transformers are accounted for in the Byron Station PRA models, and how the guidelines in RG 1.177 are met.*

EGC Response

The actions to realign the two 4.16kV safety buses from the emergency diesel generators (EDGs) to the Unit No. 2 unit auxiliary transformers (UATs) will occur while the plant is at-power, so do not fall within the scope of the probabilistic risk assessment (PRA) which models initiating events and mitigating actions in response to those initiating events. The realignment actions are a prerequisite to the extended outage time and associated PRA calculation. The original PRA calculation in Reference 1 that calculated a maximum 79-day allowed outage time begins when the plant is in a steady-state operating condition in the proposed configuration with the Unit 2 4.16kV engineered safety features (ESF) buses being fed from the Unit 2 UAT. Any risk increase during the transition period was assumed to be negligible in that original PRA calculation since the actions would be performed under the currently licensed outage time, and therefore was implicitly captured in the accepted baseline risk. This assumption was based on these two possible outcomes of the transition activities.

- Once these transition actions are completed successfully (expected within the currently allowed 72 hours), the UAT configuration will be entered, allowing entry into the extended outage time, and the original PRA calculation provided the risk of operating in this configuration.
- If these transition actions fail in a manner such that the UAT configuration will not be entered, the existing 72-hour limit would require a Unit 2 shutdown and the extended allowed outage time will not be required. A restart of Unit 2 is not expected to be allowed under these conditions, so no additional risk was assumed.

Based on discussions with NRC, it is recognized that since some of the transition actions may be unique to the attempted transition to the UAT configuration, some additional risk may exist, which is addressed in response to Sub-Question 2 below. The calculations in Sub-Question 2 show that the incremental configuration risk is small, with little impact on the completion time calculation. In addition, the identified compensatory risk management actions would serve to keep that incremental risk low.

NRC Question:

2. *If these actions are not modeled in the Byron Station PRA, provide a sensitivity study that reflects the impact of the operator actions and human error probabilities associated with these actions to realign the 4.16kV ESF busses, and justify how the guidelines in RG.177 are met.*

EGC Response

Accounting for the additional risk during the transition period, the total incremental conditional core damage probability ($ICCDP_{Total}$) would be:

$$ICCDP_{Total} = ICCDP_{Transition} + ICCDP_{UAT}$$

where $ICCDP_{Transition}$ is the previously unanalyzed risk increase during the transition period to the UAT configuration, whose risk is already calculated by $ICCDP_{UAT}$. A similar equation applies to the incremental conditional large early release probability (ICLERP).

To calculate the value of $ICCDP_{Transition}$, the actions described in the responses to Question 2 (sub-question 3) are reviewed in a manner consistent with the current Human Reliability Analyses (HRA) in the Byron PRA. However, the negative outcome of failing this action is considered to be a plant trip. This action is therefore a Type B action in that it will induce an initiating event and any human error probability associated with the alignment would add to the plant transient frequency.

In general, the actions to configure Unit 2 into the proposed long-term UAT configuration are generally familiar to the plant, and include actions similar to existing electrical operations actions (e.g., starting and aligning a diesel generator) and the existing PRA-modeled action to align the units for unit-to-unit ESF power crosstie, with the addition of some unique steps to reach the UAT configuration. Because these actions are not being performed under the typical time-pressures of other PRA-modeled sequences, it is assumed that operations will perform each step of the configuration in a deliberate manner that allows verification of each step prior to proceeding to the next step. The analysis examines the transition as being composed of these general critical steps based on the responses to sub-question 3:

- Establish the unit-to-unit ESF bus crosstie
    - This is similar to an already-modeled PRA action
- Install jumper connections to bypass breaker permissives
- Align Unit 2 ESF buses to the UATs
    - Remove links between ESF buses and non-segregated buses
    - Start Unit 2 EDGs and align the ESF buses to the EDGs
    - Deactivate the unit-to-unit ESF bus crosstie
    - Synchronize the ESF buses to the non-ESF buses and close the bus tie breakers

Unlike typical post-initiator actions that involve both a cognitive and execution error component, this action is considered to involve minimal cognitive effort as the procedure sequence will be predetermined and, with the exception of the initial OPS crew response to the loss of SAT 242-1, initiation of the actions will be directed by Byron station management. Modeling this type of action as if it was a typical post-initiator action used in the Byron model would involve using the Technique for Human Error Rate Prediction (THERP). This approach is not applied here for two reasons.

1. Some of the procedure steps executed require the performance of subtasks that are not typically evaluated within the human reliability analysis (HRA) and are not explicitly represented in traditional HRA methods (e.g., internal wire termination, etc.). As there is currently no standardized approach for the quantification of these subtasks, they presented a challenge to established HRA methods.

2. Additionally, as in the case of FLEX actions that involve many execution subtasks taken over an extended period of time, using THERP for this action would lead to an unrealistically high human error probability (HEP) for relatively simple, well-trained subtasks because of the large number of manipulation execution error probabilities that must be added together. One approach to addressing such actions is to group multiple execution steps into a single functional, perceptual unit.

As a result, the configuration subtasks are grouped and assessed in a similar manner as FLEX actions via the basic error of commission from the Accident Sequence Evaluation Program (ASEP) which has a value of 1.0E-2. While this HEP could be further reduced via the multitude of recovery opportunities inherent to actions with expansive time available for recovery, these recovery opportunities are not applied in view of the qualitative nature of the basic ASEP error of commission. These recovery opportunities include site administrative controls such as independent verification/peer checking, procedural recoveries such as parameter checks, or work order hold points.

This probability of operator error is used to represent the probability of a reactor trip at Byron Unit 2 during the transition period, which under the identified conditions with the loss of both SATs would be equivalent to a Unit 2 Loss of Offsite Power (LOOP) in the internal events PRA model. This operator-induced trip/LOOP due to the new configuration actions is the source of incremental risk during the transition period. Therefore, to calculate $ICCDP_{Transition}$, the probability of operator error is multiplied by the conditional core damage (or large early release) probability (CCDP/CLERP) from the Byron Unit 2 PRA for the expected LOOP condition.

$$ICCDP_{Transition} = Pr(\text{Operator Error}) \times CCDP$$

The Byron Unit 2 CCDP can be extracted from the current Byron Unit 2 baseline internal events PRA, which would best represent the plant configuration prior to the transition to the UAT configuration. This baseline model would still contain some conservatisms that may not apply to all possible states during the transition. For example, the baseline model would allow the unit-to-unit power crosstie to possibly fail to be implemented after the trip, whereas that crosstie is expected to already be in place during some portions of the transition.

Potential non-conservatisms in the baseline model are also addressed. One potential non-conservatism in the baseline PRA model would be any dependence between the operator failure that trips Unit 2 and subsequent operator actions to respond to the event. However, these additional mitigation actions would be separated in time from the realignment effort by the trip event, which would provide an unmistakable new cue for operators to correct their actions subsequent to the trip. This separation provides a break between any dependence between these actions. Additionally, as the alignment failure would introduce the plant trip, it would be defined as a Type B action (i.e., those actions that cause an initiating event) and would not normally be explicitly modeled to appear in the cutsets, so no dependency would be assessed. The second potential non-conservatism in the baseline PRA model is the credit for recovery of offsite power during a typical loss of offsite power event. Because this particular event would occur while both Unit 2 SATs are unavailable, this probability of power recovery is NOT credited in the calculations that follow.

The current Byron Unit 2 baseline PRA is used to calculate a CCDP and CLERP for a switchyard-centered Loss of Offsite Power (LOOP), though any type of LOOP would give the same CCDP/CLERP results with offsite power recovery disabled. The switchyard-centered LOOP is chosen based on the definition in NUREG/CR-6890 (Reference 3):

> Plant-centered LOOP events occur within the plant, up to but not including the auxiliary or station transformers. Switchyard-centered events occur within the switchyard, up to and including the output bus bar.

The calculation of CCDP and CLERP for a switchyard-centered LOOP is simply calculated by setting the switchyard-centered LOOP probability to 1.0, setting all other initiating events to FALSE, and setting the offsite power recovery failure probabilities to TRUE. The changes are summarized in Table 1 below.

Table 1: Model Modifications for CCDP and CLERP Calculation

PRA Basic Event	Description	Setting
%SY-SCLOOP2-SLIE	UNIT 2 SWITCHYARD-CENTERED LOSS OF OFFSITE POWER (SUSTAINED)	1.0
All other IEs	All other IEs	FALSE
2RC-UBR2---2SCUB	CORE UNCOVERY BEFORE POWER RECOVERY AFTER SY-CENTERED LOOP OR DLOOP - UBR2	TRUE
2RC-UBR2SDS2SCUB	CORE UNCOVERY BEFORE POWER REC AFTER SY-CENTERED LOOP OR DLOOP - UBR2 W SDS	TRUE
2RC-UBR4---4SCUB	CORE UNCOVERY BEFORE POWER RECOVERY AFTER SY-CENTERED LOOP OR DLOOP - UBR4	TRUE
2RC-UBR4SDS4SCUB	CORE UNCOVERY BEFORE POWER REC AFTER SY-CENTERED LOOP OR DLOOP - UBR4 W SDS	TRUE
2RC-UBR5---5SCUB	CORE UNCOVERY BEFORE POWER RECOVERY AFTER SY-CENTERED LOOP OR DLOOP - UBR5	TRUE
2RC-UBR5SDS5SCUB	CORE UNCOVERY BEFORE POWER REC AFTER SY-CENTERED LOOP OR DLOOP - UBR5 W SDS	TRUE

These model modifications produce a CCDP=8.07E-5 and CLERP=1.03E-6. Combining these values with the probability of the operator errors produces the incremental risk during the transition period:

$$ICCDP_{Transition} = 1E\text{-}2 \times 8.1E\text{-}5 = 8.1E\text{-}7$$

$$ICLERP_{Transition} = 1E\text{-}2 \times 1.0E\text{-}6 = 1.0E\text{-}8$$

These values show low incremental risk due to the unique actions during the transition period.

Returning to the original equation to calculate the total incremental risk,

$$ICCDP_{Total} = ICCDP_{Transition} + ICCDP_{UAT}$$

In the August 10, 2018, license amendment request (LAR), the $ICCDP_{UAT}$ is calculated as ΔCDF for the UAT configuration multiplied by the exposure time, so that formula can be substituted into the equation and re-solved for the maximum allowable time in the UAT configuration to reach the maximum ICCDP. Note that the exposure time in the LAR was conservatively calculated as only the time in the UAT configuration, and did not add in the potential time (up to 3 days) prior to completing the transition since the actual time is uncertain (between 1 and 3 days). The maximum allowed outage time duration could actually be the time it takes for the transition plus the time in the UAT configuration using this equation. The updated calculation of incremental risk, using ΔCDF and ΔLERF from Table 3.5-2 in Attachment 7 of Reference 1, shows:

$$ICCDP_{Max} = ICCDP_{Transition} + (\Delta CDF_{UAT} \times Time_{UAT})$$

$$Time_{UAT} = (ICCDP_{Max} - ICCDP_{Transition}) / \Delta CDF_{UAT}$$

$$Time_{UAT} = (1.0E\text{-}5 - 8.1E\text{-}7) / 4.6E\text{-}5 * 365 \text{ days/year} = 73 \text{ days}$$

And for Large Early Release:

$$Time_{UAT} = (1.0E\text{-}6 - 1.0E\text{-}8) / 3.2E\text{-}6 * 365 \text{ days/year} = 113 \text{ days}$$

Therefore, the maximum allowed extension time while in the UAT configuration for Unit 2 would be 73 days (compared to 79 days) when considering the incremental risk during the transition period (but still neglecting the calendar time during the transition). However, if such a failure occurred during the transition time, the extended CT would not be entered since Unit 2 would not restart in this condition.

No additional impacts on the transition risk are expected from the Fire PRA. The Fire PRA risk calculations supporting the completion time requested are contingent on a transfer from a loss of the second Unit 2 SAT to an alignment where the UAT feeds the ESF buses via the non-ESF buses. The Fire PRA assumes a reactor trip in conjunction with each fire and therefore represents a bounding risk calculation that assumes a reactor trip in conjunction with the fire at any time during the completion time, including during the transfer to the UAT.

Ultimately the risk in terms of incremental conditional core damage probability (ICCDP) including the transition actions associated with the proposed one-time Technical Specification 3.8.1, Required Action A.2, Completion Time of 60 days is as follows:

ICCDP at 60 days = ICCDP(transition) + ICCDP(UAT)

= ICCDP(transition) + [ΔCDF(UAT) * 60 days * 1year/365 days]

= 8.1E-7 (as shown in Question 2) + [4.6E-5 (as shown in Question 2) * 60 days * 1year/365 days]

= 8.4E-6

(Note that the compensatory actions as specified in the response to Question 3 below are not quantitatively credited in this calculation unless explicitly noted.)

NRC Question:

3. *Provide a summary of operator actions following a failure of SAT 242-1.*

EGC Response

Following a failure of Unit 2 System Auxiliary Transformer (SAT) 242-1, Unit 2 will remain at-power. Any non-engineered safety features (ESF) 4.16 kilovolt (kV) or 6.9 kV buses that are aligned to the SAT (e.g., Buses 258 and 259) will automatically transfer to the Unit Auxiliary Transformers (UATs). The 4.16kV ESF buses will be supplied from their respective Emergency Diesel Generator (EDG) 2A (Bus 241) and 2B (Bus 242).

1. Unit 2 Operators will meet the entry conditions for 2BOA ELEC-4, "Loss of Offsite Power Unit 2"

2. Operators verify ESF Buses 241 and 242 energized.

3. Verify essential service water (SX) cooling to 2A and 2B EDG and monitor in accordance with standard operating procedures.

4. Check safe shutdown loads are energized:
   - 480 volt (V) ESF buses
   - Charging Pumps
   - Motor Driven Auxiliary Feedwater (AF) Pump 2A
   - Component Cooling Water (CC) Pumps
   - SX Pumps

5. Check Containment Vent Isolation Valves closed.

6. Restore plant systems
   - Steam generator (SG) power-operated relief valve (PORV) controllers in AUTO
   - Reset Containment Vent Isolation
   - Notify transmission system operator (TSO) of existing conditions

7. Verify Non-ESF buses energized and proceed to 2BOA-ELEC-4, Attachment B.

8. Operators perform Normal and Reserve offsite power surveillance which will not pass due to loss of offsite power source on Unit 2. Unit 2 SATs provide one of two credited offsite sources. With both Unit 2 SATs out of service there is only one creditable offsite source.

9. Operators will prepare to crosstie Bus 241 to Bus 141:
   a. Check Bus 241 energized by EDG
   b. Check bus 141 energized by SAT.
   c. Check Reserve Feed Breaker 141 - open.
   d. Close Bus 241 reserve feeder breaker (this also defeats EDG sequencer).
   e. Shutdown 2A Motor Driven AF Pump.
   f. Shutdown unnecessary ESF equipment that was started by the load sequencer.

10. Operators perform the same actions performed in Item 9 for preparing to crosstie Bus 242 to Bus 142.

11. Operators perform manipulations to crosstie Bus 241 to Bus 141 via unit crosstie. EDG is paralleled with Unit 1 via Breaker 1414. SAT 142-1 is verified to be within its loading limits and the EDG output Breaker 2413 is opened. At this time the 2A EDG is secured.

12. Operators perform manipulations to crosstie Bus 242 to Bus 142 via unit crosstie. EDG is paralleled with Unit 1 via Breaker 1424. SAT 142-2 is verified to be within its loading limits and the EDG output Breaker 2423 is opened. At this time the 2B EDG is secured.

13. At this point, the Unit 2 ESF buses are cross-tied to the Unit 1 ESF buses. During this time the station would work through the Temporary Configuration Change Procedure to install necessary jumpers, remove SAT disconnect links to isolate the SATs from the 4.16 kV buses, and clearance order work to prepare to align the Unit 2 ESF buses to the UATs.

14. When the station is ready to proceed with placing the Unit 2 ESF buses on the UATs, both the 2A and 2B EDGs will be started in accordance with standard operating procedure, BOP DG-11, "Diesel Generator Startup."

15. To align Bus 241 to the UAT the following actions will be taken:
    a. The 2A EDG will be paralleled across Breaker 2413 to the Unit 1 SAT 142-1 currently feeding the Unit 2 ESF Bus 241.
    b. The 2A EDG will assume the load of the bus.

c. The Unit 1 to Unit 2 crosstie Breaker 1414 will be opened.
d. The Unit 2 Non-ESF SAT feed Breaker 2432 will be closed.
e. Unit 2 ESF Bus 241 will be paralleled to the Non-ESF Bus 243 by closing Breaker 2412.
f. Breaker 2411 will be closed for the Bus 241 Bus tie to Bus 243.
g. Breaker 2432 will be opened.
h. The 2A EDG will be unloaded and secured.
i. Breaker 2412 will be opened.

16. To align Bus 242 to the UAT the following actions will be taken:
    a. The 2B EDG will be paralleled across Breaker 2423 to the Unit 1 SAT 142-2 currently feeding the Unit 2 ESF Bus 242.
    b. The 2B EDG will assume the load of the bus.
    c. The Unit 1 to Unit 2 crosstie Breaker 1424 will be opened.
    d. The Unit 2 Non-ESF SAT feed Breaker 2442 will be closed.
    e. Unit 2 ESF Bus 242 will be paralleled to the Non-ESF Bus 244 by closing Breaker 2422.
    f. Breaker 2421 will be closed for the Bus 242 Bus tie to Bus 244.
    g. Breaker 2442 will be opened.
    h. The 2B EDG will be unloaded and secured.
    i. Breaker 2422 will be opened.

Following completion of the actions described above, Unit 2 will be in an alignment consistent with the proposed configuration described in EGC's license amendment request dated August 10, 2018 (i.e., all Unit 2 4.16kV and 6.9kV Buses are powered from the Unit 2 UATs).

NRC Question:

3. *Section 2.2.1 of RG 1.177 states, in part:*

> *Consistency with the defense-in-depth philosophy is maintained under the following circumstances:*
>
> > *A reasonable balance among prevention of core damage, prevention of containment failure, and consequence mitigation is preserved (i.e., the proposed change in a TS has not significantly changed the balance among these principles of prevention and mitigation) to the extent that such balance is needed to meet the acceptance criteria of the specific design-basis accidents and transients.*

Section 2.4 of RG 1.177 states, in part, with NRC staff edits in square brackets:

> *The licensee has demonstrated that implementation of the one-time only TS CT change impact on plant risk is acceptable (Tier 1):*

ICCDP [incremental conditional core damage probability] of less than [1.0E-6] and an ICLERP [incremental conditional large early release probability] (of less than [1.0E-7], or

ICCDP of less than [1.0E-5] and an ICLERP of less than [1.0E-6] with effective compensatory measures implemented to reduce the sources of increased risk.

In its letter dated August 10, 2018, the licensee described compensatory actions in Section 4.3.2 for Tier 2 actions and summarized them in Attachment 6. These actions include providing alternate firewater for centrifugal charging pumps cooling, various protective measures to the operation of the all site EDGs, and protection to the Unit No. 2 diesel-driven auxiliary feedwater pump. There are various procedural briefings and just-in-time training to operational staff.

Section 2.3.6 of RG 1.177 states, in part:

When compensatory measures are part of the TS change evaluation, the risk impact of these measures should be considered and presented, either quantitatively or qualitatively. When a quantitative evaluation is used, the total impact of these measures should be evaluated by comparison to the "small" guideline (Principle 4, as described in Part B of this regulatory guide[1]). This includes (1) evaluation of the proposed TS changes without the compensatory measures, (2) evaluation of the proposed TS changes with the compensatory measures, and (3) specific discussion of how each of the compensatory measures is credited in the PRA model or during the evaluation process.

In its letter dated August 10, 2018, the licensee presented the relative risk contributors. However, there is no qualitative or quantitative evaluation of risk reduction for each of these compensatory measures. It is unclear how consideration of mitigation as instructed in RG 1.177, and described above, is addressed.

The NRC staff requests the application be supplemented to provide an explanation of how the compensatory measures provided quantitatively and/or qualitatively impact the risk metrics and the guidelines of RG 1.177.

EGC Response

Section 4.3.2 of Attachment 1 in Reference 1 lists several sets of compensatory actions. Because many of these compensatory actions are not directly quantifiable in the overall PRA model, each set of compensatory actions are discussed in qualitative terms, with partial quantitative insights provided where possible based on simple assumptions. Unit 2 CDF is used for all quantitative insights since it is the limiting risk calculation.

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[1] When proposed changes result in an increase in core damage frequency or risk, the increases should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.

1. Protect the following components
    - Unit 2 Diesel Driven Auxiliary Feedwater (AF) Pump, 2AF01PB
    - All four Unit 1 and Unit 2 diesel generators: 1DG01KA, 1DG01KB, 2DG01KA, and 2DG01KB

Table 3.2-7 in Attachment 7 of Reference 1 provides the data for the selection of these components for protection. The Unit 2 Diesel Driven AF Pump contributes 21% to the UAT configuration CDF via two basic events for fail-to-run and fail-to-start. The Unit 2 emergency diesel generator 2A (2DG01KA) contributes 1% to the UAT configuration CDF. The other emergency diesel generators are added to the list conservatively even though they are individually below the threshold for Table 3.2-7. The total contribution of these events is therefore estimated as 22% of the UAT configuration internal events CDF.

Protection of these components consists of keeping the particular equipment rooms locked, with barriers set up and postings indicating its protected status. Protected key tags would be hung on key switches. The protected status of this equipment would be reiterated at each shift briefing and daily meetings. While the impact of these protections is not directly quantifiable, the intent is to limit the possibility of inadvertent actions that could disable or damage the protected equipment. If such protection were assumed to be comparable to a 10% reduction in component failure probabilities, then a 2.2% reduction in UAT configuration internal events CDF would be expected. This reduction would be comparable to an additional 1.7 days of operation until the risk acceptance limits were met, not including any additional credit for the Fire PRA (FPRA) model impacts.

The fail to run and fail to start failures for the diesel driven AF pump and the diesels represent a small percentage (on the order of 1%) each in the FPRA. Quantification of the risk reduction due to protection of the components with respect to FPRA risk contribution is therefore not included.

2. Limit elective maintenance unavailability on the following components
    - 2AF01PB, Unit 2 diesel driven AF pump
    - 2AF01PA, Unit 2 motor driven AF pump
    - 2DG01KA, Unit 2 Diesel Generator A
    - 2DG01KB, Unit 2 Diesel Generator B
    - 2AP231X2, Motor Control Center (MCC) 231X2
    - 2AP232X1, MCC 232X1
    - 1AP132X1, MCC132X1

Table 3.2-7 in Attachment 7 of Reference 1 also provides the data for the selection of these maintenance events, except for the 2B emergency diesel generator which is added to the list conservatively even though it is individually below the threshold for Table 3.2-7. The total contribution of these events is estimated as 15% of the UAT configuration internal events CDF.

Although with some short-term risk analyses this limitation of elective maintenance might reduce their expected unavailability to zero, such a reduction is not a reasonable assumption for this extension request due to the potentially long duration of the configuration. Instead, it is expected that elective maintenance on these components would be delayed until after the installation of the new SAT if at all possible, and regular surveillances would be reduced to the minimum allowed by Tech Specs. If such limitations were assumed to be comparable to a 25% reduction in component failure probabilities, then a 3.7% reduction in UAT configuration internal events CDF would be expected. This reduction would be comparable to an additional 2.8 days of operation until the risk acceptance limits were met, not including any additional credit for the Fire PRA model impacts.

In the Fire PRA, nominal maintenance for the AF Pumps contributes 9% of the fire risk for the UAT configuration. Assuming a similar 25% reduction of maintenance frequency would have a corresponding reduction in the configuration risk, comparable to a total of an additional 6.7 days of operation until the risk acceptance limits were met when combined with the internal events impacts.

3. Each shift, operators should brief on the following actions:
    - Establishing the 4 kV ESF power cross-tie from Unit 1 to Unit 2
    - Loading limitations for the 4 kV ESF power cross-tie from Unit 1 to Unit 2
    - Supplying the Unit 2 diesel-driven AF pump, 2AF01PB, with alternate essential service water (SX) system cooling
    - Aligning fire protection cooling to centrifugal charging (CV) pumps, 2CV01PA and 2CV01PB, upon loss of SX
    - Locally failing air to the Unit 2 AF Flow Control, 2AF005, valves on loss of main feedwater
    - Byron Station Procedure BOP DG-22, "Diesel Generator Operation after Auto Start"
    - Byron Station Procedure 2BOA ELEC-4, "Loss of Offsite Power Unit 2"
    - Byron Station Procedure 2BEP ES-0.1, "Reactor Trip Response Unit 2," actions concerning natural circulation cooldown
    - Byron Station Procedure BOP DO 16, "Filling the Unit 2 Diesel Auxiliary Feedwater Pump Day Tank"
    - Byron Station Procedure BOP CC 10, "Alignment of the U-0 Component Cooling Water (CC) Pump and U-0 CC Heat Exchanger (HX) to a Unit"

Table 3.2-6 in Attachment 7 of Reference 1 provides the data for the selection of the third and fourth actions to be included as compensatory actions. The first, second, and fifth actions appear lower on the list of important operator actions. The last five items on the briefing list are identified as important procedures due to their relationship with the AC power systems and other typically important events, but are not directly represented in the PRA model. The total contribution of the first five events is estimated as 28% of the UAT configuration internal events CDF.

While the impact of these operator briefings is not directly quantifiable, the intent is to better prepare operators to respond to important actions while in the UAT configuration. If this improved preparation were assumed to be comparable to a 10% reduction in operator failure probabilities, then a 2.8% reduction in UAT configuration internal events CDF would be expected. This reduction would be comparable to an additional 2.2 days of operation until the risk acceptance limits were met, not including any additional credit for the Fire PRA model impacts.

In the Fire PRA, operator action failure probabilities identified in compensatory actions associated with operator briefings contribute 17% of the fire risk for the UAT configuration. Assuming a similar 10% reduction in operator failure probabilities would have a corresponding reduction in the configuration risk, comparable to a total of an additional 4.3 days of operation until the risk acceptance limits were met when combined with the internal events impacts.

The following additional compensatory actions are highlighted as important specifically from the Fire PRA results.

1. Aside from the period of aligning UAT-to-ESF bus supply, maintain SAT supply feed breakers to ESF buses, 2412 and 2422, racked out

This compensatory action is explicitly credited in the fire risk quantification.

2. Aside from the period of aligning UAT-to-ESF bus supply, open test switches for breakers 2412/2422 to prevent lockout relays from impacting breakers 2413 and 2414/2423 and 2424 operation

This compensatory action is explicitly credited in the fire risk quantification.

3. Each shift, operators should brief on the following actions:

   a. Filling the Unit 2 Diesel AF Pump Day Tank from the 125,000 or 50,000 gallon fuel oil storage tanks per 2BOP DO-13
   b. Providing makeup capability to the SX Cooling Tower Basin before inventory is low per BAR 0-37-A8 and BOP SX-12

The impacts of these compensatory actions are included in the discussion above with the internal events actions.

4. Risk Management Actions (RMAs) applicable for this extended CT window will be completed per OP-AA-201-012-1001, "Operations On-Line Fire Risk Management," (These actions protect against fire impacting key redundant equipment).

5. Prior to entering the TS 3.8.1.A Action statement for repair of Unit 2 SATs, an operating crew shift briefing and pre-job walkdowns are suggested to be conducted to reduce and manage transient combustibles and to alert the staff about the increased sensitivity to fires in the fire zones specified in Table 3.3-5 of Attachment 7 is shown below. Operating crew shift briefings will continue to be conducted every shift throughout the duration of the CT period. Additionally, planned hot work activities in these fire zones

should be minimized during the time within the extended TS Condition 3.8.1.A CT. In the event of an emergent issue requiring hot work in one of the listed zones, additional compensatory actions will be developed to minimize the risk of fire. The fire zones listed in Table 3.3-5 of Attachment 7 were identified based on risk significance in the FPRA results. Walkdowns are intended to reduce the likelihood of fires in certain zones by limiting transient combustibles, ensuring transients, if required to be present, be located away from fixed ignition sources, and eliminating or isolating potential transient ignition sources, (e.g., energized temporary equipment and associated cables). Table 2 below identifies the risk-significant fire zones to which compensatory actions apply.

Table 2: Risk-Significant Fire Zones to Which Compensatory Actions Apply

Fire Zone	Fire Zone Description
11.6B-0	Auxiliary Building Offices, 426' El. (risk significant cables above false ceiling), transient fire exposure
5.4-2	Division 22 Miscellaneous Electrical Equipment and Battery Room
5.2-1	Division 11 ESF Switchgear Room
5.2-2	Division 21 ESF Switchgear Room
2.1-0	Control Room
11.4C-0	Radwaste/Remote Shutdown Control Room
11.7-0	Auxiliary Building HVAC Exhaust Complex
11.6-0	Auxiliary Building General Area, 426' El.

These Fire Zones in which additional fire watch and transient combustible controls are to be applied during the period which the completion time is applied contribute 53% of the fire risk for the UAT configuration. Assuming these compensatory actions resulted in a 20% reduction in the associated ignition frequency, these actions would result in a reduction of the fire contribution to the CT extension risk of approximately 10.6% and an additional 16 days of operation until the risk acceptance limits were met.

Although these compensatory actions do not have a computational basis for direct quantitative impacts, the assumptions provided show the approximate impact of the individual compensatory action groups. If all the assumptions were combined, the internal events Unit 2 CDF during the UAT configuration could be reduced by about 8.7% and the Fire Unit 2 CDF could be reduced by about 15%, which would equate to an additional 28 days of completion time. Table 3 provides a summary of these quantitative insights regarding the compensatory actions.

Table 3: Summary of Compensatory Action Insights

Comp Actions	Model	Assumed Credit	CDF Reduction	Increase in CT
Equipment Protection	FPIE	10%	2.2%	1.7 days
	Fire	NA	NA	NA
Elective Maintenance	FPIE	25%	3.7%	2.8 days
	Fire	25%	3.0%	3.8 days
Operator Briefings	FPIE	10%	2.8%	2.2 days
	Fire	10%	1.7%	2.2 days
Fire Watch	FPIE	NA	NA	NA
	Fire	20%	10.6%	15.8 days
Totals	**FPIE**	**varies**	**8.7%**	**6.7 days**
	Fire	**varies**	**15.3%**	**21.8 days**
	TOTAL			**28.4 days**

NRC Question:

4. *RG 1.177, Section A-1.3, states, in part:*

> *Contributions from common-cause failures (CCFs) need special attention when calculating the increased risk level R_1. If the component is down because of a failure, the common-cause contributions involving the component should be divided by the probability of the component being down because of failure since the component is given to be down. If the component is down because it is being brought down for maintenance, the CCF contributions involving the component should be modified to remove the component and to only include failures of the remaining components (also see Regulatory Position 2.3.1 of Regulatory Guide 1.177).*

In its letter dated August 10, 2018, the licensee proposes to incorporate changes to the model in order to assess the impact of the cross-tie of Unit No. 2 to the Unit No. 1 4.16 kV safety buses (bus 241 tied to bus 141, and bus 242 tied to bus 142). In this configuration, all 4.16kV safety buses will be ultimately fed from Unit No. 1 SATs 142-1 and 142-2.

The NRC staff requests the application be supplemented to provide an explanation of how the CCF probabilities have been adjusted accordingly to account for assumed failures of SATs 242-1 and 242-2.

EGC Response

First, the question states that "*all 4.16kV safety buses will be ultimately fed from Unit No. 1 SATs 142-1 and 142-2.*" This is true only for a short time (within the existing completion time) while recovering from the failure of SAT 242-1 and transitioning to the longer-term UAT configuration. This condition may also occur following a later Unit 2 accident sequence as a backup power configuration if the Unit 2 emergency diesel generators are not available to provide power to the safety buses.

To address the concept of common cause failures of the SATs, the root cause analysis of the SAT 242-2 failure is reviewed (Reference 6). It states that the most likely root cause of the failure of SAT 242-2 is that the partial transformer oil drain and refill methodology used to perform an X2 bushing replacement exposed the HV lead insulation to air and contaminants which, in combination with previous insulation degradation associated with the HV lead suspected to be sustained during the 2012 open phase event, resulted in partial discharges that lead to the failure following re-energizing the transformer. This failure was the result of an aggregate contribution of multiple events which degraded the dielectric qualities of the SAT 242-2 transformer insulation.

Based on evaluation of the dissolved gas analysis and oil sample results immediately following the 2012 Loss of Phase event and based on trending of the same results since, SAT 242-1 did not experience the same level of insulation degradation that SAT 242-2 experienced. Similarly, a review of testing results for SAT 242-1 does not show a similar impact to the degree of polymerization and the estimated percentage of remaining life at the time of the 2012 sustained open phase event. Therefore, the testing results for SAT 242-1 indicate that the condition of the paper insulation is more normal for SAT 242-1 than was the case for SAT 242-2 at the time of failure.

In addition, neither of the Byron Unit 1 SATs has experienced an operational transient to the same magnitude as the 2012 Loss of Phase event. The Byron Unit 1 SATs have associated dissolved gas analysis and testing trends that indicate less transformer degradation than either Byron SAT 242-1 or Byron SAT 242-2. This root cause analysis supports the conclusion that the failure of SAT 242-2 does not indicate a particular common cause failure mode that the other SATs would be susceptible to. However, this license amendment request is based on a potential future failure of SAT 242-1, so an assessment is provided considering any possible common cause failure conditions between SATs 242-1, 142-1, and 142-2.

The assumed future failures of these three remaining SATs could occur under three different conditions.

1. If common cause failures of SATs 142-1 and 142-2 follow closely in time with failure of SAT 242-1, per the definition in NUREG/CR-6268 (Reference 4) that "components fail within a selected period of time such that success of the probabilistic risk assessment (PRA) mission would be uncertain", then both units will shut down and not be restarted without the currently allowed configuration of SATs. Therefore, this occurrence does not add to the incremental risk for the purpose of the requested extended CT.

2. If common cause failures of SATs 142-1 and 142-2 do not follow closely in time with failure of SAT 242-1, then they would not be strictly considered as a direct common cause per the definition in Reference 4. Given the differences in testing results discussed above, this occurrence seems possible. Such failure could occur under two different conditions.

    a. If the Unit 1 SATs fail as an initiating event on Unit 1, it would not have a direct impact on the operating Unit 2. Since Unit 2 CDF is the limiting risk calculation, this occurrence would not have a significant impact on the requested extension.

b. If the Unit 1 SATs fail during a Unit 2 accident sequence, it would prevent the use of the unit-to-unit crosstie as a backup power source if the Unit 2 emergency diesel generators were unavailable. This occurrence could have an impact on the requested extension since Unit 2 CDF is the limiting risk calculation.

The SATs are not explicitly modeled in the PRA; they are considered part of the offsite power source which is modeled as an initiating event using generic industry and plant-specific data to develop its frequency. To evaluate the additional risk due to an occurrence of situation 2.b above, a new failure event is added to the internal events PRA model to represent failure of the Unit 1 SATs during the 24-hour mission time of a Unit 2 event.

Per the 2015 update to NUREG/CR-6928 (Reference 5), transformers have an independent failure rate of 2.89E-6/hr. The 2015 update to NUREG/CR-6268 (Reference 4) does not contain common cause factors for transformers, so a commonly accepted conservative beta factor of 0.1 is assumed. Combining these values produces a common cause failure rate for the Unit 1 SATs of 2.89E-7/hr. Over the 24-hour mission time of the Unit 2 PRA, that produces a failure probability of 6.94E-6. A new event (SAT-CCF) is added to the PRA model under the same gates as the existing human operator actions to align the unit-to-unit power crosstie, since the failure of the Unit 1 SATs prevents this action. The resulting calculation shows no change in Unit 2 CDF in the UAT configuration. This is an expected result since the probability of multiple Unit 1 SAT failures not close in time to the potential Unit 2 SAT 242-1 failure is less than 1% of the operator action failure probability.

NRC Question:

5. *In its letter dated August 10, 2018, the licensee proposes, in the event of a failure of the SAT 242-1, to operate for 79 days with both Unit No. 2 SATs failed.*

   The NRC staff requests the application be supplemented to provide a summary of needed operator actions if a Unit No. 1 SAT fails during the 79 days, including an evaluation of loading on the remaining Unit No. 1 SAT, which could be called upon to provide power to Byron Station, Unit Nos. 1 and 2, ESF buses.

EGC Response

In this scenario, it is assumed that SAT 242-1 has failed such that both Unit 2 SATs 242-1 and 242-2 are de-energized. The Unit 2 4.16 kV ESF buses are cross-tied to the Unit 2 4.16 kV Non-ESF buses and are being powered by the Unit 2 Main Generator via the UATs. Unit 2 is assumed to be operating at full power.

Both Unit 1 SATs 142-1 and 142-2 are energized and supplying power to the Unit 1 4.16 kV ESF buses. Unit 1 is assumed to be operating at full power.

Both Units 1 and 2 would have one inoperable required qualified circuit and would be in TS 3.8.1 Required Action A.2 to restore the inoperable circuit (SAT 242-1 or SAT 242-2) within 60 days.

If one of the Unit 1 SATs (SAT 142-1 or 142-2) were to fault, both Unit 1 SATs would trip and de-energize, since they are fed by a common Switchyard Bus (i.e., Bus 6). EDGs 1A and 1B would automatically start on 4.16 kV ESF bus undervoltage. The EDGs would re-energize the 4.16 kV ESF Buses 141 and 142 and sequence on the required loads. The 6.9 kV Non-ESF Buses 158 and 159 would automatically fast bus transfer from the SATs to the UATs. The 4.16 kV Non-ESF Buses 143 and 144 and the 6.9 kV Non-ESF Buses 156 and 157 are normally fed by the UATs and would remain powered by the UATs. In summary, after a Unit 1 SAT trip, the ESF buses would be powered by the U1 EDGs, and the Non-ESF buses would be powered by the U1 UATs, and Unit 1 would continue to operate at full power.

A Unit 1 SAT fault would not affect operation of Unit 2. The Unit 2 UATs would continue to supply power to the Unit 2 ESF and Non-ESF buses, and Unit 2 would continue to operate at full power.

With both the Unit 1 and Unit 2 SATs de-energized, both units would now have two inoperable required qualified circuits and would be in TS 3.8.1 Required Action D.1 to restore one qualified circuit to operable status within 24 hours. After the initial operator response to the transient on Unit 1 for the Unit 1 SAT trip, the operators would take actions as required by TS for each unit.

The station would take actions to identify and isolate the faulted Unit 1 SAT. The crosstie links would be reconfigured to allow the non-faulted Unit 1 SAT to be able to provide power to all of the Unit 1 ESF and Non-ESF buses. The operable Unit 1 SAT would be re-energized. Then the 4.16 kV ESF buses would be transferred from EDGs 1A and 1B to the operable Unit 1 SAT, and then the EDGs would be shutdown. The Non-ESF loading on the single Unit 1 SAT would be controlled to ensure that the Unit 1 SAT would remain capable of supplying power to the Unit 1 ESF buses and also to the Unit 2 ESF buses, if required. With restoration of a Unit 1 SAT, both Units 1 and 2 would have one operable required qualified circuit and would be able to exit TS 3.8.1 Condition D.

Since only one SAT would be available to support operation of both units, there would be significant load shedding required of Non-ESF loads after a Unit 1 trip to control the overall loading on the SAT. Therefore, after a Unit 1 SAT has been returned to operation and one offsite circuit returned to service for both units, the station would evaluate the current plant conditions and electrical loadings. Further actions would be based on safety and plant risk. This may include controlled shutdowns of one or both units, if warranted. If Unit 2 were to be shutdown, the Unit 2 ESF Buses 241 and 242 would be crosstied to Unit 1 ESF Buses 141 and 142, respectively, and powered from the operable Unit 1 SAT. The remaining Unit 2 Non-ESF buses would be de-energized. If both units were shutdown, the single operable Unit 1 SAT would supply power to all of the Unit 1 ESF and Non-ESF buses and also to the Unit 2 ESF buses. After a second SAT on either Unit 1 or 2 has been returned to service, Byron Station would then consider restarting Units 1 and/or 2, if they had been shut down.

NRC Question:

6. *In its letter dated September 13, 2018 (ADAMS Accession No. ML18256A392), the licensee provided a list of PRA action items required to be completed prior to implementation of the 10 CFR 50.69 risk categorization process.*

The NRC staff requests that the application be supplemented to describe the impact of these items on the risk assessment provided in the licensee's letter dated August 10, 2018.

EGC Response

From the internal events perspective, the impact of the 10 CFR 50.69 implementation items is small. These required implementation items exist in the internal events working model referenced in some parts of Table 3.6-1 and Table 4-2 in Attachment 7 of Reference 1. The sensitivity calculation mentioned in those tables that includes all the impacts on the internal events model shows less than 2% difference in the Unit 2 internal events ΔCDF.

From the Fire PRA perspective, the impact of resolution of the 10 CFR 50.69 implementation items on the CT calculation for the 2 SATs out of service condition is expected to be small. In-process model updates associated with the incorporation of these changes confirm that the incorporation of these changes does not result in significant changes in the fire risk. Each of the implementation items specified in the 10 CFR 50.69 RAI response referenced above (in RAI 12 of that response) are identified below and a more detailed discussion of their impact on the PRA is provided for each item.

Item 1 (Associated with 10 CFR 50.69 RAI 3.a):
The internal events and fire PRA models will be updated to versions that include the updated HVAC modeling prior to implementation of the 10 CFR 50.69 risk categorization process.

Internal Events Model Impact on CT Extension Analysis: Included in sensitivity calculation discussed above and in the LAR.
Fire PRA Model Impact on CT Extension Analysis: No impact, this is associated with HVAC modeling required for HELB scenario evaluation. The Fire PRA does not postulate a HELB in conjunction with a fire.

Item 2 (Associated with 10 CFR 50.69 RAI 3.b)
Where breaker coordination could not be confirmed for a unit, the applicable model is being updated so that load side cables are designated as causing the loss of the associated power supply. The FPRA models for Byron and Braidwood will be updated to incorporate failures required to account for instances where breaker coordination cannot be confirmed prior to implementation of the 10 CFR 50.69 risk categorization process.

Internal Events Model Impact on CT Extension Analysis: No impact - Fire impact only.
Fire PRA Model Impact on CT Extension Analysis: The in-process update of this model confirms that the addition of the uncoordinated breaker load cables as impacting the associated bus has only a minor impact on the Fire PRA results. The impact of this issue on the Fire PRA is limited to specific buses whose loss is not altered by the CT extension configuration and is not expected to result in a unique impact that would alter the calculation of the CT extension Fire PRA risk increase.

Item 3 (Associated with 10 CFR 50.69 RAI 3.c)
To ensure that the impact of the CCDP and CLERP scaling factor adjustments is accounted for in the categorization process, a Fire PRA sensitivity in addition to the sensitivities required by NEI 00-04 Table 5-3 will be performed. If the Fire PRA is updated in the future to eliminate the scaling factor adjustment, this sensitivity calculation would no longer be required.

> Internal Events Model Impact on CT Extension Analysis: No impact - Fire impact only.
> Fire PRA Model Impact on CT Extension Analysis: This sensitivity was required for the 50.69 application in order to ensure that its impact would not alter equipment categorization process FPRA inputs in a manner that would alter their categorization. A sensitivity is not considered necessary for the CT extension since the contribution of control room abandonment scenarios to the CT extension results is on the order of 5% of the risk, and the impact of the CCDP/CLERP adjustments will be a small fraction of this value, thereby ensuring that the impact of this adjustment is on the risk results will be very small.

Item 4 (Associated with 10 CFR 50.69 RAI 3.d)
Identification of all wall mounted panel configurations with four or more switches will be completed and any resulting changes to the Byron and Braidwood FPRA models to incorporate the impact of these panels will be made prior to implementation of the 10 CFR 50.69 risk categorization process.

> Internal Events Model Impact on CT Extension Analysis: No impact - Fire impact only.
> Fire PRA Model Impact on CT Extension Analysis: A walkdown of the wall mounted panels was performed and only a few new fire scenarios were identified with limited target impact. Incorporation of these scenarios will have a minor impact and may actually result in a reduced risk since these benign scenarios will result in a small reduction in frequency of more significant fire scenarios.

Item 5 (Associated with 10 CFR 50.69 RAI 3.e)
The Byron and Braidwood FPRA models that will be used for 10 CFR 50.69 implementation will include a new sump clogging value consistent with the WCAP-16362-NP guidance.

> Internal Events Model Impact on CT Extension Analysis: Included in the Model of Record used for the LAR.
> Fire PRA Model Impact on CT Extension Analysis: The impact of the random failure associated with the sump clogging factor will have a negligible impact on the CT extension fire risk quantification.

Item 6 (Associated with 10 CFR 50.69 RAI 8.c)
The Byron and Braidwood Fire PRAs to be used to support the implementation of the 50.69 categorization will retain a 1E-06 joint HEP floor value and justification will be included in the Fire PRA documentation for specific HEP combinations for which a value of less than 1E-05 is used.

> Internal Events Model Impact on CT Extension Analysis: No impact - Fire impact only.
> Fire PRA Model Impact on CT Extension Analysis: The impact of the JHEP floor value applied for the Fire PRA is expected to have minimal impact on the delta risk calculated

for the CT extension fire risk. The refinement of any combinations which are significant contributors to allow for the use of a floor value less than 1E-06 will mitigate any potential impact of the use of the lower JHEP floor value.

Item 7 (Associated with 10 CFR 50.69 RAI 11)
The additional failure contribution of the Westinghouse RCP Shutdown Seal Bypass failure mode will be added to the Byron and Braidwood Internal Events and Fire PRA models prior to implementation of the 10 CFR 50.69 risk categorization process.

Internal Events Model Impact on CT Extension Analysis: Included in sensitivity calculation discussed above and in the LAR.
Fire PRA Model Impact on CT Extension Analysis: Because of the minimal impact of this additional failure contribution in the internal events model, the impact on the Fire PRA Model is also expected to be minimal.

References

1. Letter from D. M. Gullott (Exelon Generation Company, LLC (EGC)) to U.S. NRC, "License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2," dated August 10, 2018

2. Letter from J. S. Wiebe (NRC) to B. C. Hanson (EGC), "Byron Station, Unit Nos. 1 and 2 - Supplemental Information Needed for Acceptance of Requested Licensing Action Re: One-Time Extension of Technical Specification 3.8.1, 'AC Sources-Operating,' A2 Completion Time (EPID L-2018-LLA-0218)," dated December 12, 2018

3. NUREG/CR-6890, Reevaluation of Station Blackout Risk at Nuclear Power Plants, Analysis of Loss of Offsite Power Events: 1986-2004, November 2005

4. NUREG-CR-6268, "Common-Cause Failure Database and Analysis System: Event Data Collection, Classification, and Coding, Revision 1, dated August 2007 (with 2015 updated parameter estimations at https://nrcoe.inl.gov/resultsdb/ParamEstSpar"

5. NUREG/CR-6928, "Industry Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants," dated February 2007 (with 2015 updated component reliability values at https://nrcoe.inl.gov/resultsdb/AvgPerf

6. Byron Root Cause Report, "Loss of Bus 13 – SAT 242-2 Failure," Issue Report No. 4153681, dated August 14, 2018

Byron Station, Units 1 and 2

Supplemental Information Related to License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 2 – UPDATED PROPOSED TECHNICAL SPECIFICATIONS CHANGE (MARKUPS)

3.8.1-1

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources-Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

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

b. Two Diesel Generators (DGs) capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

------------------------------------NOTE------------------------------------
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more buses with one required qualified circuit inoperable.	A.1	Perform SR 3.8.1.1 for the required OPERABLE qualified circuits.	1 hour AND Once per 8 hours thereafter
	AND		
	A.2	Restore required qualified circuit(s) to OPERABLE status.	72 hours AND 17 days from discovery of failure to meet LCO *

(continued)

*For the failure of Unit 2 System Auxiliary Transformer (SAT) 242-1 coincident with the July 6, 2018, failure of Unit 2 SAT 242-2, restore the required qualified circuit to OPERABLE status within 60 days.

Byron Station, Units 1 and 2

Supplemental Information Related to License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 3 – UPDATED REVISED (CLEAN) TECHNICAL SPECIFICATIONS PAGE

3.8.1-1

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources-Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

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

b. Two Diesel Generators (DGs) capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

------------------------------------NOTE------------------------------------
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more buses with one required qualified circuit inoperable.	A.1	Perform SR 3.8.1.1 for the required OPERABLE qualified circuits.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	A.2	Restore required qualified circuit(s) to OPERABLE status.	72 hours* <u>AND</u> 17 days from discovery of failure to meet LCO*

(continued)

* For the failure of Unit 2 System Auxiliary Transformer (SAT) 242-1 coincident with the July 6, 2018, failure of Unit 2 SAT 242-2, restore the required qualified circuit to OPERABLE status within 60 days.

Byron Station, Units 1 and 2

Supplemental Information Related to License Amendment Request for a One-Time Extension to Technical Specification 3.8.1, "AC Sources-Operating," Required Action A.2

ATTACHMENT 4

UPDATED UNIT 2 SYSTEM AUXILIARY TRANSFORMER 242-2 REPAIR AND TESTING SCHEDULE

ATTACHMENT 4

UPDATED BYRON STATION, UNIT 2 SYSTEM AUXILIARY TRANSFORMER 242-2 REPAIR AND TESTING SCHEDULE

<u>Anticipated Schedule for the Replacement and Testing of Byron Station, Unit 2 System Auxiliary Transformer (SAT) 242-2 (For Information Only)</u>

ABB Begins construction by: 7/26/2018
Transformer Design Specifications complete by: 8/3/2018
Construction for installation begins: 11/15/2018
Factory Acceptance Testing completed by: 12/21/2018
Transformer Manufacture complete: ~12/21/2018
Shipping of Transformer to Byron Station: 12/26/2018 – 1/31/2019
Engineering: 8/1/2018 - 2/25/2019
Transportation to site complete by: 1/31/2019
Transformer assembly: 2/8/2019 - 2/28/2019
Installation work window scheduled for: 2/28/2019 – 3/10/2019
Complete – SAT 242-2 Declared Operable: 3/13/2019