Response to

Request for Additional Information No. 11, Revision 0

6/16/2008
U.S. EPR Standard Design Certification
AREVA NP Inc.
Docket No. 52-020
SRP Section: 08.03.01 - AC Power Systems (Onsite)
SRP Section: 08.03.02 - DC Power Systems (Onsite)
SRP Section: 08.04 - Station Blackout
Application Section: FSAR Chapter 8
EE Branch

Question 08.03.01-1:

Page 8.3-3 (8.3.1.1.1) of the FSAR states that “a loss of voltage at one of 6.9 kV (BDA) buses initiates an automatic fast transfer of the offsite power source, maintaining offsite power to all four divisions by switching the affected bus power supply to the unaffected EAT. The fast transfer minimizes voltage decay and frequency difference to limit motor torque during the transfer, thus minimizing equipment degradation.” Explain how the automatic fast transfer scheme works and how the scheme prevents transfer into a faulted bus. Elaborate on whether any single failure vulnerability exists with the transfer scheme between the motive (AC) and control power (DC) within the affected divisions. Is the same transfer scheme used for NPSS?

Response to Question 08.03.01-1:

A response will be provided to this question by October 15, 2008.

Question 08.03.01-2:

Page 8.3-3 (8.3.1.1.1) of the FSAR states that “EPSS divisions are functionally independent and physically separated from the others during normal bus alignments.” It also states that “alternate feeds are provided between EPSS divisions to provide normal and standby power to required safety-related systems, safety-related support systems, or components that do not have four 100 percent redundant trains when certain electrical components, including EDGs, are out of service.” List all ESF loads on EPSS buses and identify equipment that are needed for 100 percent redundancy in each division (and its divisional pairs) for safety-related functions to mitigate loss of offsite power event (LOOP) and the accident with LOOP. FEMA performed on Table 8.2-3 states that EUPS loads division 1 and 2 are powered from the battery for two hours. Explain what this means.

Response to Question 08.03.01-2:

A response will be provided to this question by October 15, 2008.

Question 08.03.01-3:

Page 8.3-26 (8.3.1.2.4) of the FSAR states that "the EPPS has four divisions, and the four EPPS divisions are normally functionally independent and physically separated from each other." It states further that "The EPSS safety-related loads are separated between the divisional pairs and a loss of one divisional pair will not prevent the minimum safety-related functions from being performed." Although the EPR EPPS has four divisions, the alternate feed is not functionally independent, thus requiring a divisional pair concept. The operating experience has shown that the alternate feed configuration requires circuit breaker re-alignments, which could be susceptible to human errors. It also imposes operational restrictions (e.g., in and out of technical specification). Provide the rational for using the alternate feed design over four independent divisions for all safety-related functions and provide the risk insights (calculations) represented by the alternate feed vs. the four independent division concept. Also explain the importance of: divisional pair (1-2 and 3-4) concepts for accomplishing minimum safety-related functions vs. alternate feed configuration for performing safety-related functions. Is there any difference? Is it possible that one division from each divisional pair (i.e., 1-3 or 2-4, etc) is left to accomplish the minimum safety-related function?

Response to Question 08.03.01-3:

The alternate feed design feature is only used during specific maintenance activities, emergency diesel generator (EDG) maintenance for example, and the normal configuration for the emergency power supply system (EPSS) is four functionally independent divisions. The use of the alternate feed during EDG maintenance is to provide a standby source of power to certain safety-related components within the division when the EDG is out of service. The alternate feed reduces the risk associated with the EDG being out of service since certain safety-related components within the division would still be functional during a postulated design basis event (DBE) with an associated loss of offsite power (LOOP). Since the alternate feed lineup does not introduce any new risk concerns (at least not a likely risk concern as an increase in a trip frequency or degradation in divisional spatial independence), and it provides an additional protection when an EDG is in maintenance. The U.S. EPR probabilistic risk assessment (PRA) has shown a very small (negligible, <1 percent) decrease in the total risk (core damage frequency) as result of this lineup.

The safety-related systems which are powered during an alternate feed lineup are associated with four categories. The categories consist of the following:

- Two train systems—the U.S. EPR consists of several safety-related two train systems. The safety-related trains are designed for single failure but do not include provisions for taking the train out of service for maintenance for an extended period of time during operation. The trains are not affected by the initiating event and thus both trains are available to mitigate the accident. The following two train systems are capable of being alternately fed:
  - Annulus ventilation system.
  - Safeguard Building controlled-area ventilation.
  - Main control room iodine filtration system.
  - Fuel pool cooling system.
  - Extra borating system.

- Valve isolation functions—certain safety-related functions (containment isolation, steam generator blowdown isolation, main feedwater isolation) use redundant motor-operated valves (MOV) to perform the required function. The MOVs are redundant to meet the single failure criterion. Implementing the alternate feed maintains the redundant power supplies to these components to maintain the safety function capability consistent with the single failure criterion.

- Four train systems—main steam relief trains (MSRT) valves and the emergency feedwater (EFW) discharge lines can be affected by the initiating event and also require two trains at certain times during the DBE to perform the safety-related function. To meet the single failure criterion, all four trains are required to be operable. Thus, during EDG maintenance the alternate feed provides a source of standby power to all four trains.

- Support systems—the safety-related systems in the three foregoing categories require the associated support systems of electrical, instrumentation and control (I&C), and heating, ventilation and air conditioning (HVAC) for proper operation. The required support systems are also alternately fed.

The divisional pair concept describes the philosophy of how the alternate feed configuration is applied to the electrical design. The alternate feed can only be configured between Divisions 1 and 2 (divisional pair) and Divisions 3 and 4 (divisional pair). The divisional pair concept is then used when assigning a two train system to an electrical division. An example of assigning power supplies to a two train system is the annulus ventilation system. One train of annulus ventilation is assigned to Division 1 and the other train is assigned to Division 4. During EDG No. 1 maintenance, an alternate feed is established between Division 1 and Division 2 to provide a standby power source to the annulus ventilation in Division 1. Divisions 1 and 2 functionally make a divisional pair during the alternate feed alignment. If EDG No. 2 fails to start (single failure) both electrical Divisions 1 and 2 are unavailable to mitigate the accident. Divisions 3 and 4 are available to mitigate the accident and the annulus ventilation assigned to Division 4 is available to perform the safety function. Redundant features of described safety-related systems are divided between the two divisional pairs to make sure the safety-related function can be completed concurrently with a single failure to the electrical distribution system as shown in the annulus ventilation system example.

A worst-case single failure could lead to the following possible scenarios for performing the safety-related function during an alternate feed lineup with an EDG out of service for maintenance.

- Failure of the EDG associated with the alternate feed—in this case both divisions associated with the alternate feed (divisional pair) are lost and either Divisions 1 and 2 or Divisions 3 and 4 are available to mitigate the accident with an associated LOOP.

- Failure of an EDG not associated with the alternate feed—in this case both divisions associated with the alternate feed are unaffected and one of the other two divisions is lost (e.g., EDG No. 1 in maintenance with alternate feed established and a failure of EDG No. 3). Division 1 (alternate fed buses only); Division 2 and Division 4 are available to mitigate the accident with an associated LOOP.

The divisional pair concept in application of implementing the alternate feed provides a standby source of power to safety-related components when an EDG is out of service. By maintaining

divisional pairs physically and electrical separate and selecting diverse power sources between the divisional pairs to accomplish required safety functions, the electrical distribution contains required independence and redundancy to perform the required safety functions assuming a single failure.

Table 08.03.01-3-1 and Figures 08.03.01-3-1 through 08.03.01-3-4 illustrate the alternate feed load distribution and safety system functionality. With the Division 1 EDG in maintenance, an event occurs with a LOOP and single failure while the alternate feed is installed from Division 2 to Division1. In the first example, (Figure 08.03.03-3-3), the single failure is the Division 2 EDG. In the second example (Figure 08.03.01-3-4) the single failure is the Division 3 EDG. In both cases safety system functionality is preserved.

Table 08.03.01-3-1—Alternate Feed Load Distribution

Alternate Fed Loads	DIV 1	DIV 2	DIV 3	DIV 4
EFW Valves	X	X	X	X
MSIVs / MSRTs	X	X	X	X
MFW Isolation Valves	X	X	X	X
S/G Isolation Valves	X	X	X	X
PCIVs	X	X	X	X
Anti Dilution Valves	X			X
Extra Boration System	X			X
Fuel Pool Cooling System	X			X
Annulus Ventilation	X			X
KLC System	X			X
CR Iodine Filtration	X			X
2 Hr Battery Chargers	X	X	X	X
HVAC Support / Emergency lighting	X	X	X	X

Notes for Table 08.03.01-3-1:

1. Alternate feed is only designed between Division 1 and 2 (one divisional pair) and Division 3 and 4 (another divisional pair).
2. A two train safety-related function which requires electrical power has one train assigned to Division 1 or 2 and the other redundant train assigned to Division 3 or 4.

Figure 08.03.01-3-1—Divisional Pair Concept

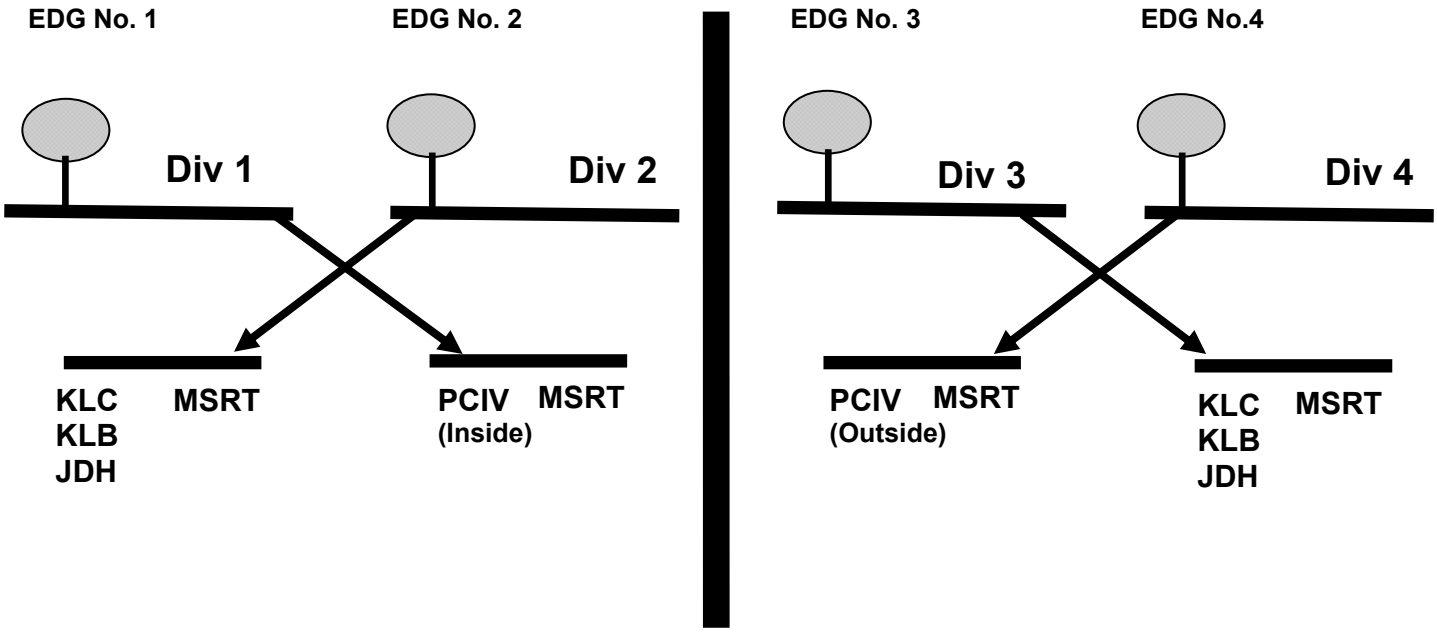


Figure 08.03.01-3-2—Divisional Pair Concept (EDG No. 1 Maintenance)

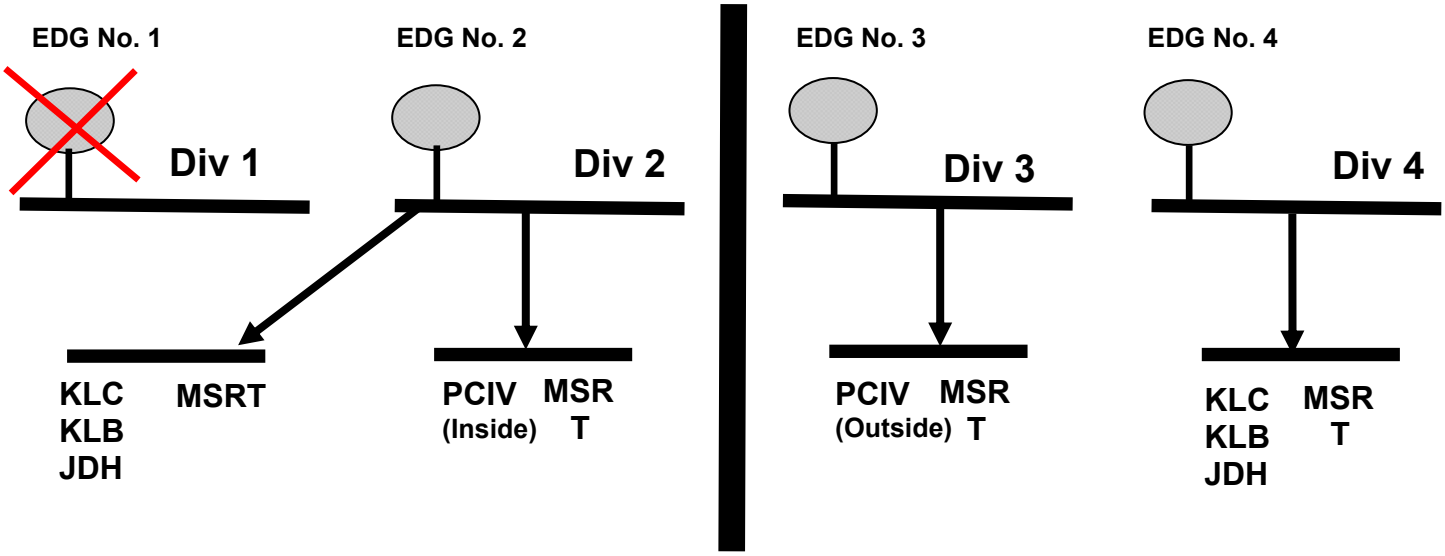


Figure 08.03.01-3-3—EDG No. 2 Single Failure

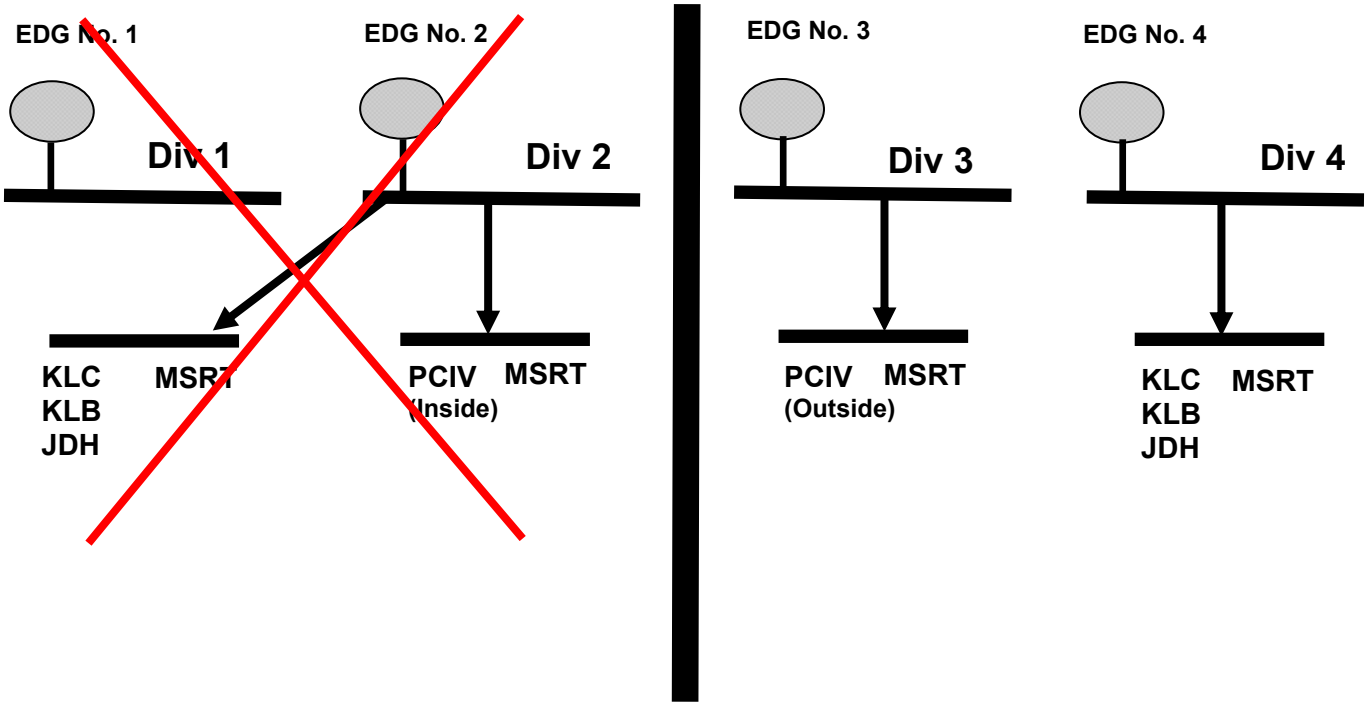
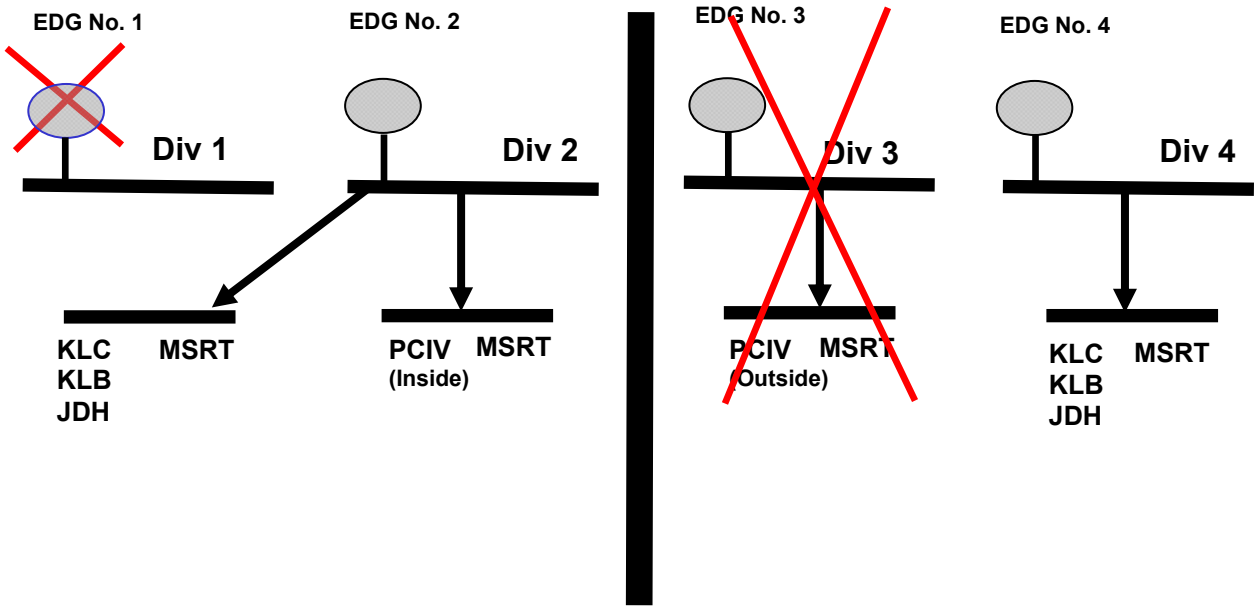


Figure 08.03.01-3-4—EDG No. 3 Single Failure



FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.03.01-4:

Page 8.3-7 (8.3.1.1.3) of the FSAR cites that "the alternate feed circuit protection scheme uses circuit breakers so that a malfunction of the components performing the alternate feed function or a malfunction of the components being alternately fed does not result in unacceptable influences in the division that supplies the power." Discuss details of the protection scheme and demonstrate that the alternate feed configuration does not result in unacceptable influences in the division that supplies (AC and DC control) power. How long does it take to establish the alternate feed connection? When will the procedure for establishing the alternate feed be submitted for staff review?

Response to Question 08.03.01-4:

While the alternate feed is in service, the division supplying the alternate feed is protected by two Class 1E breakers in series from a fault in an alternate fed bus. The alternate feed circuit breakers overcurrent pickup setpoints and time delays will be coordinated with the support division such that a fault in the supported division will be isolated from the division supplying power through the alternate feed.

For example, (refer to U.S. EPR FSAR Tier 2, Section 8.3, Figure 8.3-2—Emergency Power Supply System Single Line Drawing Sheet 2 of 3) if Division 1 was supporting Division 2 via the alternate feed, the circuit breaker in switchgear 32BDB to supply bus 32BDB from 31BDA would be installed and closed (Figure match point "D"). There is also a separate upstream circuit breaker in 31BDA to provide isolation (protection and coordination) for the alternate feed. The two breakers in series and properly coordinated with each other will prevent an unacceptable influence from an alternate fed bus fault to the supply bus. The series circuit breaker arrangement also provides a single failure-tolerant design if the downstream alternate feed supply breaker fails to operate as required.

The direct current (DC) control power for the emergency power supply system (EPSS) components is supplied by the respective division Class 1E uninterruptible power supply system (EUPS). During an alternate feed line up as described above, the Division 2 battery charger 32BTP02 would be in service providing the DC battery charger power from 32BMB. The battery charger alignment to 32BMB provides a standby source of power to the DC system during an alternate feed lineup. A fault in Division 2 isolated as described would limit the impact of the fault to the Division 2 EUPS (e.g., fault resulting in loss of power to bus 32BMB). Division 1 EUPS would remain unaffected, and continue to provide control power to Division 1 EPSS components.

Establishment of the alternate feed involves isolation (de-energizing) of the bus to be fed (in the previous case bus 32BDB) to satisfy RG 1.6 guidance for providing an interlock to prevent paralleling two redundant standby sources. Once the interlock is satisfied by having the normal source circuit breaker open and interlocked, the alternate feed circuit breaker is closed. Following closing the alternate feed circuit breaker and re-energizing the bus, any loads that were shifted prior to de-energizing the bus are then re-started or re-aligned as desired. The time involved in implementing the alternate feed must be within the Technical Specification Completion Time for the condition of the buses being de-energized, Chapter 16, Section 3.8.9. Additionally, the condition that is the purpose for implementing the alternate feed, an inoperable emergency diesel generator (EDG) for example, also will have a completion time associated with the inoperable equipment. The completion time for this action (having the alternate feed

installed) is consistent with the guidance of RG 1.93 for restoring full redundancy to onsite power supplies. For the equipment outage example given, the allowed outage time for the switchover of the buses is much shorter than the allowed equipment (EDG) outage time. The procedures for establishing the alternate feed are the responsibility of the combined license (COL) applicant and are to be provided consistent with COL item 13.5-1 in U.S. EPR FSAR Table 1.8-2—U.S. EPR Combined License Information Items.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.03.01-5:

In Page 8.3-12 (8.3.1.5) of the FSAR, each EDG generator load requirement has been identified in Table 8.3–4, Table 8.3–5, Table 8.3–6 and Table 8.3–7. Page 8.3-16 states that load tests will be performed to verify an EDG output of 9500 kW or greater while maintaining steady-state voltage at 6.9 kV, ± 0.5 percent and steady-state frequency at 60 Hz ± 0.5 percent. The EPR FSAR also states that "the voltage regulator and excitation system provide response and operating characteristics to meet RG 1.9 for load step changes and full load operation." Provide a summary of the results of calculations and assumptions that support EDG sizing and voltage profiles for each load step change. In addition, the staff noticed that values for the above EDG output, voltage and frequency are different from that of Technical Specification (TS) tested values. Explain why?

Response to Question 08.03.01-5:

A response will be provided to this question by September 30, 2008.

Question 08.03.01-6:

Page 8.3-19 (8.3.1.1.8) of the FSAR, for those inaccessible power cables installed in duct bank, or underground, FSAR cites that they should be testing periodically to detect degradation. If degradation is detected or suspected (e.g., manholes located below ground water level), the FSAR should expand further that the COL applicants should develop a testing program as described in NRC Generic Letter 2007-01.

Response to Question 08.03.01-6:

A response will be provided to this question by September 30, 2008.

Question 08.03.01-7:

Page 8.3-23 (8.3.1.1.11) of the FSAR states that “Load flow and voltage regulation studies will be verified by measurement to demonstrate distribution system capability to provide minimum starting voltage to the Class 1E motors during static and dynamic conditions.” Elaborate when and who will verify (by measurement) the actual starting voltage to the Class 1E motors, degradation setpoints, and voltage measurements in the as-built electrical distribution system as described Section B.4 of BTP 8-6, “Adequacy of Station Electric Distribution System Voltages.”

Response to Question 08.03.01-7:

A response will be provided to this question by September 30, 2008.

Question 08.03.01-8:

Page 8.3-32 (8.3.1.3.1) of the FSAR mentioned that a detailed analysis has been performed that demonstrates adequate voltage regulation is maintained at safety-related equipment terminals during worst case system configuration and load profile for expected power source voltage levels. Provide a summary of the results of: 1. Load flow/voltage regulation and under/overvoltage protection studies that demonstrate system capability to provide minimum required voltage to safety-related equipment terminals and assumptions used for the analysis. 2. EDG load requirements, acceptance criteria and assumptions used (8.3.1.1.5). 3. Minimum voltage requirements for safety-related equipment and demonstration of electrical distribution system capability (8.3.1.1.11) and assumptions used. 4. Class 1E inverter sizing and assumptions used (8.3.2.4.3).

Response to Question 08.03.01-8:

A response will be provided to this question by September 30, 2008.

Question 08.03.01-9:

Page 8.3-33 (8.3.1.3.2) of the FSAR stated that a detailed analysis has been performed to evaluate worst case bolted three phase short-circuit fault currents in the onsite AC distribution system. Provide the analyses, and assumptions used that are performed to evaluate acceptable ratings for equipment such as circuit breakers for switchgear bus and containment penetration assembly.

Response to Question 08.03.01-9:

A response will be provided to this question by September 30, 2008.

Question 08.03.01-10:

Page 8.3-33 (8.3.1.3.3) of the FSAR stated that equipment sizing was performed using a spreadsheet load (including 13.8 and 6.9 kV BOP) list and was subsequently verified using the ETAP load flow/voltage regulation and short circuit analysis results. Provide the results from equipment sizing studies, and acceptance criteria and assumptions used.

Response to Question 08.03.01-10:

A response will be provided to this question by September 30, 2008.

Question 08.03.01-11:

SRP 8.3.1-11 Page 8.3-33 (8.3.1.3.4) of the FSAR cited that the electrical distribution system protection and coordination studies are performed in accordance with IEEE Std. 242-2001 to develop a selectively coordinated system. Provide a summary of the results (including typical coordination curves) from those studies, and acceptance criteria and assumptions used.

Response to Question 08.03.01-11:

As described in U.S. EPR FSAR Tier 2, Section 8.3.1.1.3, coordination studies will be conducted in accordance with IEEE Std 242-2001 (Ref. 1) to verify the protection feature coordination capability to limit the loss of equipment due to postulated fault conditions. The information required to perform these studies is needed from as-procured equipment and thus the results of the studies are unavailable for review at present. IEEE Std 242-2001 will provide an acceptable standard for the performance of the study. The studies will be completed prior to placing the electrical equipment in service.

References for Question 08.03.01-11:

1. IEEE Std 242-2001, “IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems,” Institute of Electrical and Electronics Engineers, 2001.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.03.01-12:

Correct references shown on the following FSAR pages: Page 8.1-6 (8.1.4.3.1 General Design Criteria) - add GDC-5 in the list. Page 8.3-19 from duct backs to duct banks Page 8.3-27 from Table 8.3-9 to Table 8.3-11 Page 8.3-32 from reference 25 to reference 6 Page 8.3-37 from reference 16 to reference 17 Page 8.3-37 from Table 8.3–11 to Table 8.3–10 Page 8.3-39 from reference 36 to reference 37 Pages 8.1-3, 8.3-41, 50, and 52 from reference Tables 8.3-13 thru 16 to Tables 8.3-12 thru 15 Page 8.3-46 from reference 9 to reference 10 Page 8.3-47 from Table 8.3-12 to Table 8.3-11 Pages 8.3-49, 50, 52 and 54 from Table 8.3-11 to Table 8.3-10 Page 8.3-67 from load group 9 to group 6 for EFW Page 8.4-1 from Table 8.3-9 to Table 8.2-3.

Response to Question 08.03.01-12:

In the U.S. EPR FSAR, the following changes will be made:

In U.S. EPR FSAR Tier 2 Section 8.1.4.3.1, “GDC-5” will be added to the list of general design criteria referenced for U.S. EPR compliance.

In U.S. EPR FSAR Tier 2 Section 8.3.1.1.8 under the heading Raceway and Cable Routing, the fourth sentence in the third paragraph will be changed to indicate, “Examples of cables that use underground duct banks include……”

In U.S. EPR FSAR Tier 2 Section 8.3.1.2.4 under the heading Conformance with RG 1.53, the reference to U.S. EPR FSAR Tier 2 Table 8.3-9—Onsite AC Power System Failure Modes and Effects Analysis, is correct as stated. U.S. EPR FSAR Tier 2 Table 8.3-9 will be moved to this table location, making the referenced table number correct.

In U.S. EPR FSAR Tier 2 Section 8.3.1.2.11 under the heading BTP 8-6 Adequacy of Station Electric Distribution System Voltages, the reference in the second paragraph will be changed to indicate “Reference 6”.

In U.S. EPR FSAR Tier 2 Section 8.3.1.3.8, the reference in the third sentence, tenth paragraph will be changed to indicate, “Reference 17.”

In U.S. EPR FSAR Tier 2 Section 8.3.2.1.1.1, the reference to U.S. EPR FSAR Tier 2 Table 8.3-11—Onsite DC Power System Component Data Nominal Values, is correct as stated. U.S. EPR FSAR Tier 2 Table 8.3-11 will be moved to this table location, making the referenced table number correct.

In U.S. EPR FSAR Tier 2 Section 8.3.2.1.1.2, the reference in the first sentence, fourth paragraph will be changed to indicate, “Reference 37.”

In U.S. EPR FSAR Tier 2 Sections 8.1.3, 8.3.2.1.1.6, 8.3.2.3.3 and 8.3.2.4.1, the references to U.S. EPR FSAR Tier 2 Tables 8.3-13 through 8.3-16 are correct as stated. U.S. EPR FSAR Tier 2 Tables 8.3-13 through 8.3-16 for the Class 1E uninterruptible power supply nominal loads will be moved to these table locations, making the referenced table numbers correct.

In U.S. EPR FSAR Tier 2 Section 8.3.2.2.4 under the heading Conformance with RG 1.75, the reference in the third sentence, first paragraph will be change to indicate, “Reference 10.”

In U.S. EPR FSAR Tier 2 Section 8.3.2.2.4 under the heading Conformance with RG 1.53, the reference to U.S. EPR FSAR Tier 2 Table 8.3-12—Class 1E Uninterruptible Power Supply System Failure Modes and Effects Analysis, is correct as stated. U.S. EPR FSAR Tier 2 Table 8.3-12 will be moved to this table location, making the referenced table number correct.

In U.S. EPR FSAR Tier 2 Sections 8.3.2.3.1, 8.3.2.3.2, 8.3.2.4.4 and 8.3.2.4.6 the references to U.S. EPR FSAR Tier 2 Table 8.3-11 are correct as stated. U.S. EPR FSAR Tier 2 Table 8.3-11 will be moved to this table location, making the referenced table numbers correct.

The description of emergency feedwater (EFW) pump starting sequence in U.S. EPR FSAR Tier 2 Tables 8.3.4 through 8.3-7 note 5 is correct as stated. During a loss of offsite power (LOOP) only condition, the medium head safety injection pump (load step 2), low head safety injection pump (load step 3) and EFW pump (load step 6) starting is omitted along with the five second time delay associated with the load step sequence. The load steps still exist, they are just not actuated in this scenario. The omission of these steps results in sequencing to the last load step 15 seconds earlier than a loss of offsite power/loss of coolant accident (LOOP/LOCA) condition. The EFW pump start is inhibited until the last load step has been completed (load group 9) at 40 seconds. The EFW pump is available to start based on a steam generator low level initiation once the start inhibit has been removed. No change to the U.S. EPR FSAR has been made related to this question.

In U.S. EPR FSAR Tier 2, Section 8.4.1.1, the reference to U.S. EPR FSAR Tier 2, Table 8.3-9, is correct as stated. U.S. EPR FSAR Tier 2, Table 8.3-9, will be moved to this table location, making the referenced table number correct.

FSAR Impact:

U.S. EPR FSAR, Tier 2, Sections 8.1.4.3.1, 8.3.1.1.8, 8.3.1.2.11, 8.3.1.3.8, 8.3.2.1.1.2, 8.3.2.2.4 and table locations will be revised as described in the response and indicated on the enclosed markup.

Question 08.03.01-13:

LCO 3.8.1 of EPR Technical Specification (Section 8- Electrical Power System) requires: two qualified circuits between the offsite transmission network and the onsite Class 1E AC electrical power distribution system; and four emergency diesel generators (EDGs) capable of supplying the onsite Class 1E power distribution subsystems to be operable. When one EDG is found to be inoperable, 120 days are allowed to restore the inoperable EDG to operable by crediting for establishing the alternate feed within 72 hours. Establishing the alternate feed can not be considered as an acceptable required action for an inoperable EDG. The staff finds that 120 days is excessive. This is also not consistent with RG. 1.93 that requires restoring an inoperable EDG within 72 hours. How is the allowed outage of 120 days (by entering LCO 3.8.1) whenever an EDG needs maintenance justified? Consider a design change that eliminates the alternate feed configuration, so that LCO 3.8.1 of the EPR TS can be operable with three of four EDGs.

Response to Question 08.03.01-13:

The proposed U.S. EPR Technical Specifications are consistent with the intent of the guidance contained in RG 1.93 with respect to limiting conditions for operation (LCO). As stated in RG 1.93:

“Plants with more power sources than are required by GDC-17 can tolerate the loss of one or more sources and still meet the LCO. During the normal course of operation, however, any nuclear power plant may lose power sources to the extent that the LCO is not met. This guide addresses such cases.

This guide describes operating procedures and restrictions acceptable to the Regulatory staff which should be implemented if the available electric power sources are less than the LCO. This guide is applicable to single- and multi-unit plants, including multi-unit plants that share the required electric power sources.

The LCO with respect to available electric power sources is an electric power system that satisfies General Design Criterion 17 (GDC-17), "Electric Power Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," of 10 CFR Part 50 by including the following electric power sources: (1) two physically independent circuits from the offsite transmission network, each of which is either continuously available or can be made available within a few seconds following a loss-of-coolant accident (LOCA), (2) redundant onsite a.c. power supplies, and (3) redundant onsite d.c. power supplies.”

As written, the specific regulatory guidance provided in RG 1.93 that addresses five levels of degradation of the power systems apply only when the available electric power sources do not meet minimum redundancy and diversity requirements. The five levels of degradation, as written, directly apply to existing operating plants where a total of two emergency diesel generators (EDG) supply the two redundant trains of emergency core cooling system equipment. Some interpretation is required to apply the guidance to plants that have more than two trains, more than one diesel per train, or plants that share diesels between units.

The U.S. EPR has adequate redundancy and diversity with:

- Two offsite circuits.
- Three operable EDGs with the alternate feed established in the divisional pair (between Divisions 1 and 2 or Divisions 3 and 4) with the inoperable EDG.

Thus, establishing an alternate feed to a division with an inoperable EDG provides the redundancy of required primary and support equipment that does not have four 100 percent redundant trains (e.g., containment isolation valves, extra boration system, and control room emergency filtration) after a loss of offsite power/design basis accident. For the U.S. EPR, the specific guidance in RG 1.93 regarding the first level of degradation (i.e., the available AC power sources are one less than the LCO) can be exited when the alternate feed is established or when the EDG is returned to operable status. Therefore, the RG 1.93 recommended 72 hour allowed outage time for the first level of degradation apples to the establishment of the alternate feed.

Since the U.S. EPR safety analysis assumptions are satisfied with three operable EDGs and the alternate feed established, the RG 1.93 degradation levels are not entered with one EDG inoperable. Therefore, an indefinite allowed outage time could be justified for one inoperable EDG. However, in order to reflect a conservative operational philosophy, but still allow a reasonable time for divisional maintenance, a 120 day allowed outage time for an inoperable EDG was determined to be reasonable.

AREVA NP believes that the NRC recognized this or similar potential plant configuration issues when draft RG DG-1195 (Proposed Revision 1 to Regulatory Guide 1.93, dated December 1974) was developed and issued in May, 2008. It states:

“For evolutionary plant designs that have three or four safety trains and have excess redundancy in their onsite power systems, the restrictions imposed on such plants on the loss of required onsite power sources may differ from those recommended in this guide and should be evaluated on a case-by-case basis.”

Therefore, establishment of the alternate feed and the proposed outage time for an inoperable EDG with an alternate feed properly aligned is reasonable and consistent with current and proposed regulatory guidance.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.03.01-14:

Any sequencer failure will affect the ability of the associated DG to power its respective safety loads under all conditions. The staff notes that LCO 3.8.1 does not require automatic load sequencers for each division to be operable. Explain why the load sequencer is not required for EDGs for EPR.

Response to Question 08.03.01-14:

A typical existing operating station has a specific component called a load sequencer, which includes relays and time delay circuits. The U.S. EPR does not have such a component. The load sequencing function is performed by the instrumentation and control (I&C) protection system. Specifically, the software within the actuator logic units (ALU) will control the timing of electrical loads being sequenced on the emergency diesel generators (EDG) after a loss of offsite power. Appropriate surveillance requirements for the ALUs are included within limiting conditions for operation (LCO) 3.3.1. In addition, LCO 3.3.1 requires the protection system to maintain the EDG Start on Degraded Grid Voltage function operable in Modes 1 through 4 or any time the associated EDG is required to be operable per LCO 3.8.2, AC Sources - Shutdown.

With regards to LCO 3.8.1, proposed U.S. EPR Surveillance Requirement 3.8.1.11 demonstrates the as-designed operation of the standby power sources during loss of the offsite source. This test verifies actions encountered from the loss of offsite power (LOOP), including shedding of the nonessential loads and energization of the emergency buses and respective loads from the EDG. It further demonstrates the capability of the EDG to automatically achieve the required voltage and frequency within the specified time. This surveillance satisfies Revision 4 of Regulatory Guide 1.9, Application and Testing of Safety-Related Diesel Generators in Nuclear Power Plants, Section 2.2.5 - LOOP Test.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.03.01-15:

Tables 8.3-4 thru 7 indicates that each EDG reaches rated speed and voltage/output breaker closes in 15 seconds. Note No. 13 of the above tables also indicates that the 15 seconds is an estimated time. In addition, staff's review of sequencing of EDG loads (e.g., ECCS and EFW pumps) seems to indicate a timing inconsistency between FSAR Chapters 15 (transient and accident) analyses and Chapter 8 (Electric Power). Explain the inconsistency. When will the exact time will be known and it will be reflected in the FSAR and TS?

Response to Question 08.03.01-15:

As indicated in U.S. EPR FSAR Tier 2, Section 8.3.1.1.5, fourth paragraph in the Performance – Emergency Diesel Generators subsection and in U.S. EPR FSAR Chapter 16 Tech Spec Surveillance Requirement 3.8.1.7, the start-up time of an unloaded diesel generator, from the emergency start signal to nominal speed, rated generator frequency and voltage, is less than or equal to 15 seconds. Since the exact time of emergency diesel generator (EDG) output breaker closing may be less than 15 seconds, note 13 in the U.S. EPR Tier 2, Section 8.3, Tables 8.3-4 through 8.3-7 indicates the timing sequence of each EDG load step group may be slightly different since the load sequence times are based on a Time = 0 equal to the EDG output breaker closing and not the EDG start signal.

U.S. EPR FSAR Tier 2 Chapter 15 transient and accident analyses assume an EDG output breaker closing time of 15 seconds from the loss of offsite power (LOOP) condition. A review of U.S. EPR FSAR Tier 2 Chapter 15 found no timing inconsistency between U.S. EPR FSAR Tier 2 Chapter 15 and Tier 2 Chapter 8. A safety injection signal (SIS) based on the parameter initiating the signal may not be the same time as the engineered safety feature component actuation. For example, U.S. EPR FSAR Tier 2, Section 15.6, Table 15.6-21—SBLOCA – Sequence of Events for 6.5 Inch Break with LOOP, indicates a reactor trip at approximately 4 seconds (initiation of LOOP). The SIS signal is generated at approximately 17 seconds. In this case the medium head safety injection (MHSI) pump breaker will close at 24 seconds (nominal), low head safety-injection pump breaker will close at 29 seconds (nominal), and so on as shown in the EDG load sequence based upon a maximum EDG start and ready to load time of 15 seconds. As shown in U.S. EPR FSAR Tier 2 Table 15.6-21, MHSI injection is not credited until 246 seconds into the event.

The EDG output breaker nominal closing time of 15 seconds following EDG start on LOOP signal is accurately reflected in the U.S. EPR FSAR and Tech Specs. This value is assumed in U.S. EPR transient and accident analyses as appropriate and bounds the credited safety function performance requirements. The EDG capability to provide power to the emergency power supply system buses in a loss of power condition is verified with U.S. EPR FSAR Tier 1, Section 2.5.1, ITAAC item 2.5.1.6.1.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.03.01-16:

SR 3.8.1.9 and SR 3.8.1.10 of TS uses power factor of 90 percent (.9) for EDG synchronized with offsite power. However, Page 8.3-26 of FSAR states that "In developing EDG load rating, performance characteristics for motors were calculated based on 90 percent efficiency, MVA sizing developed using a power factor of 85 percent or less." Explain the difference.

Response to Question 08.03.01-16:

Regulatory Guide 1.9 Sections C.2.2.7 and 2.2.8 supplements IEEE Std 387-1995 (Ref. 1) largest load rejection test and design-load rejection test in part by indicating that the emergency diesel generator (EDG) is operating at its design load power factor. This power factor is representative of the actual inductive loading an EDG would see under postulated accident conditions, which includes motors, heaters, lighting, battery chargers. The power factor of 0.9 in SR 3.8.1.9 and 3.8.1.10 is the design load power factor that represents the total system inductive load.

The power factor of 85 percent or less indicated in U.S. EPR FSAR Tier 2, Section 8.3.1.2.4, under the heading of Conformance with RG 1.9, was used in assigning a power factor to motors during the early phase of the design. The motor power factor is used during the initial sizing of the EDG as a conservative value in accordance with RG 1.9 Section C.1.2. This value does not represent the total system inductive loading under accident conditions, but the motor power factors in the absence of fully substantiated motor performance characteristics. To provide additional clarity, the second sentence of this section will be changed to indicate, "In developing EDG load rating, performance characteristics for motors were calculated based on 90 percent efficiency and power factors of 85 percent or less."

References for Question 08.03.01-16:

1. IEEE Std 387-1995, "IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations," Institute of Electrical and Electronics Engineers, 1995.

FSAR Impact:

U.S. EPR FSAR, Tier 2, Section 8.2.2.4 will be revised as described in the response and indicated on the enclosed markup.

Question 08.03.02-1:

Page 8.1-2 (8.1.2) of the FSAR states that “the Class 1E uninterruptible power supply (EUPS) has four separate and redundant 250 Vdc divisions that provide power to EUPS DC loads and to inverters that power safety-related and select non-safety-related loads.” Identify those select non-safety-related loads, and explain how it was accounted for sizing of EUPS batteries.

Response to Question 08.03.02-1:

Divisions 2 and 3 provide power to the special emergency lighting system, which is non-safety-related. Divisions 1 through 4 provide power to the radiation monitoring system, which provides some Type E post-accident monitoring (PAM) variables. The special emergency lighting load and PAM loads are accounted for in the EUPS battery sizing calculation by factoring these loads as continuous loads throughout the battery loading scenario.

FSAR Impact:

The FSAR will not be changed as a result of this question.

Question 08.03.02-2:

Page 8.3-38 (8.3.2.1.1.1) of the FSAR references Table 8.3–10, "Onsite DC Power System Component Data Nominal Values." In Table 8.3-10, correct the number of cells (i.e., 240 vs. 120) shown for EUPS and 12UPS batteries. Why do division 1 and 2 battery chargers have a higher required output current requirement (i.e., 382 amp vs. 333 amps) than division 3 and 4, despite division 1 and 2 batteries having a smaller capacity battery (i.e., 1800 AH vs. 2147 AH)? Are four trains shown for 12UPS (AC/DC) and 12UPS (DC/DC) (i.e., components 11 and 12) correct?

Response to Question 08.03.02-2:

U.S. EPR FSAR Tier 2, Section 8.3, Table 8.3-11—Onsite DC Power System Component Data Nominal Values, Component 1, EUPS Batteries, correctly reflects Divisions 1 and 4 have 240 cells, while Divisions 2 and 3 have 120 cells. Division 1 and 4 batteries are arranged in two stings of 120 battery cells to meet the 250 volts direct current (VDC) duty cycle. Division 2 and 3 batteries are arranged with one string of 120 battery cells to meet the 250 VDC duty cycle.

Division 1 and 4 Class 1E uninterruptible power supply (EUPS) loads are greater than Division 2 and 3 loads, requiring the additional string of battery cells. The parallel arrangement of the two 120 battery cell strings allows a smaller individual cell storage capacity of 1800 amp/hours (AH) at an eight hour rate; Division 1 and 4 EUPS loads are greater than Division 2 and 3 loads, requiring the additional string of battery cells. The parallel arrangement of the two 120 battery cell strings allows a smaller individual cell storage capacity of 1800 AH at an eight hour rate, therefore the battery for Divisions 1 and 4 EUPS has an overall 3600 AH at an eight hour rate, whereas the single string applied in Division 2 and 3 has a 2147 AH at an 8 hour rate. The number of battery cells depicted in the U.S. EPR FSAR Tier 2, Table 8.3-11, is correct and will not change as a result of this question.

The single string applied in Division 2 and 3 has a 2147 AH at an 8 hour rate. The number of battery cells depicted in the U.S. EPR FSAR Tier 2, Table 8.3-11, is correct and will not change as a result of this question.

The U.S. EPR FSAR Tier 2, Table 8.3-11, Component 2, EUPS battery chargers, shows Divisions 1 and 4 having a required output current of 382 amps (A), while Divisions 2 and 3 have a required output current of 333 A. The additional required current related to Divisions 1 and 4 is to meet the greater loading associated with Divisions 1 and 4. This loading for Divisions 1 and 4 corresponds to a larger overall battery than Divisions 2 and 3 (240 cells vs. 120 cells).

The four trains shown in the U.S. EPR FSAR Tier 2, Table 8.3-11, components 11 and 12 are correct. They are depicted in U.S. EPR FSAR Tier 2, Figure 8.3-6—12-Hour Uninterruptible Power Supply System Single Line Drawing as the 480 volts alternating current (VAC) to 24 VDC converts powered from 31/32/33/34BRB and 250 VDC to 24 VDC converters powered from 31/32/33/34BUE, respectively. 480 VAC motor control centers (MCC) 31BRB and 32BRB, and 250 VDC switchboards 31BUE and 32BUE are supplied from 12-hour uninterruptible power supply system (12UPS) train 1. 480 VAC MCCs 33BRB and 34BRB, and 250 VDC switchboards 33BUE and 34BUE are supplied from 12-Hour uninterruptible power supply (12UPS) train 2.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.03.02-3:

Page 8.3-49 (8.3.2.3.1) of the FSAR mentioned load flow studies performed for switchboards. Provide the results of dc load flow calculations and the assumptions used to demonstrate the adequacy of bus voltage values with these system loads and sources.

Response to Question 08.03.02-3:

A response to this question will be provided by October 15, 2008.

Question 08.03.02-4:

Page 8.3-49 (8.3.2.3.2) of the FSAR mentioned short-circuits studies. Provide the results of the dc short circuit calculations to determine the applicable circuit breaker interrupting ratings, and maximum bus bracing current capabilities. Explain why dc protection and coordination studies were not mentioned? Also provide a summary of the results of these studies (including typical coordination curves).

Response to Question 08.03.02-4:

The direct current (DC) short circuit calculations were performed using a simplified model in the electrical transient analyzer program (ETAP). The Class 1E uninterruptible power supply (EUPS) DC short-circuit analysis was performed to determine DC equipment ratings based upon available short-circuit fault current. The available short-circuit current fault values are as follows:

- Short-circuit current of 31BUC and 34BUC is 38.73 kA.
- Short-circuit current of 32BUC and 33BUC is 29.25 kA.

The U.S. EPR FSAR section referenced (Tier 2, Section 8.3.2.3.2) was written to address RG 1.206 Section C.I.8.3.2.3 (2) Short-Circuit Studies, which does not address protection and coordination studies. As described in U.S. EPR FSAR Tier 2, Section 8.3.1.1.3, coordination studies will be conducted in accordance with IEEE Std 242-2001 (Ref. 1) to verify the protection feature coordination capability to limit the loss of equipment due to postulated fault conditions. The information required to perform these studies is needed from as-procured equipment, and thus the results of the studies are unavailable at present for review. IEEE Std 242-2001 will provide an acceptable standard for the performance of the study. The studies will be completed prior to placing the electrical equipment in service.

References for Question 08.03.02-4:

1. IEEE Std 387-1995, “IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations,” Institute of Electrical and Electronics Engineers, 1995.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.03.02-5:

Page 8.3-50 (8.3.2.3.3) of the FSAR mentioned various dc system equipment sizing studies. Provide a summary of the sizing calculations for battery, charger, inverter, switchgear bus, and breakers, panels, and cables and assumptions used.

Response to Question 08.03.02-5:

A response to this question will be provided by October 15, 2008.

Question 08.04-1:

Page 8.4-1 (8.4.1) of the FSAR states that the "SBODGs have the capacity and capability to bring the plant to and maintain the power plant in a non-design basis accident (non-DBA) safe shutdown condition without any support systems powered from the preferred power supply (offsite grid) or EPSS. Safe shutdown (non-DBA) means bringing the plant to those shutdown conditions specified in the U.S. EPR technical specifications as hot standby." However, page 21 of SECY 94-084 recommends the preferred method of demonstrating compliance with 10 CFR 50.63 for evolutionary design to be a spare full-capacity alternate ac (AAC) power source of a diverse design and that the AAC power source powers a larger complement of shutdown equipment to bring the plant to cold shutdown (not hot standby). Based on the above guidance, the AAC power source should bring the plant to a cold shutdown and the size of AAC should be the same size as an EDG (9500 kW) of US-EPR. The proposed SBODG for US-EPR CD provides 3900 kW which would bring the plant only to hot standby. Explain how EPR plans to satisfy the SECY guidance with regard sizing of the SBODG.

Response to Question 08.04-1:

Station Blackout End State

It is neither required nor desirable to bring the plant to cold shutdown during a station blackout event.

SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," March 28, 1994, is for passive plant designs and therefore does not appear to be directly applicable to the U.S. EPR. However, at page 6 of SECY-90-016, "Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements," June 26, 1990, it is stated, "The staff believes that the preferred method of demonstrating compliance with 10 CFR 50.63 is through the installation of a spare (full capacity) alternate ac power source of diverse design that is consistent with the guidance in Regulatory Guide 1.155, and is capable of powering at least one complete set of normal safe shutdown loads." This statement is in support of a staff request that the Commission approve imposition of an alternate alternating current (AC) source for evolutionary advanced light-water reactors (ALWR). By letter dated June 26, 1990, the Commission approved in part and disapproved in part the staff's recommendations in SECY-90-16. With respect to station blackout, item II.C (page 3) states, "The Commission (with all Commissioners agreeing) has approved the staff's position that the evolutionary ALWRs have an alternate ac power source of diverse design capable of powering at least one complete set of normal shutdown loads." This statement does not identify the required end state operating mode.

The definition, "alternate ac source" contained in 10 CFR 50.2 states that an alternate AC source "Has sufficient capacity and reliability for operation of all systems required for coping with station blackout and for the time required to bring and maintain the plant in safe shutdown," and provides that "Safe shutdown (non-design basis accident (non-DBA)) for station blackout means bringing the plant to those shutdown conditions addressed in plant technical specifications as Hot Standby or Hot Shutdown, as appropriate (plants have the option of maintaining the RCS at normal operating temperatures or at reduced temperatures)."

Regulatory Guide 1.155, “Station Blackout,” provides a method for determining the required coping duration. For the U.S. EPR, this duration is no more than 8 hours, and may be less depending on the result of certain site-specific “factors” defined in Regulatory Guide 1.155. Regulatory Guide 1.155 and the NRC correspondence included in Appendix K to NUMARC 87-00, Revision 1, provide NRC endorsement of NUMARC 87-00, Revision 1, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors. NUMARC 87-00, Revision 1, Appendix I Question I.8.119 also defines safe shutdown as “hot shutdown or hot standby as appropriate…”

As stated in U.S. EPR FSAR Tier 2 Section 8.4.2.6.1, the U.S. EPR design envelopes an eight hour coping duration for the worst case site conditions. This duration was determined in accordance with Regulatory Guide 1.155, Table 2, “Acceptable Station Blackout Duration Capability,” and NUMARC 87-00, Revision 1, Section 3, “Required Coping Duration Category.” As defined by 10 CFR 50.2, “Station Blackout” means a complete loss of alternating current power to the essential and nonessential switchgear buses. Therefore, the Reactor Coolant Pumps are unavailable during a station blackout. The cooldown rate during the resulting natural circulation cooldown is greatly reduced as compared to a normal cooldown, so that cold shutdown is not achievable during an eight-hour station blackout event. Even if a cooldown to cold shutdown was possible, this would be undesirable, because it would cause shrinkage of the reactor coolant system inventory.

Alternate AC Source (Station Blackout Diesel Generator) Size

The alternate AC source and emergency diesel generators (EDG) have different design bases, and therefore the nominal sizes are different.

Referring again to 10 CFR 50.2, the alternate AC source is defined to have sufficient capacity for operation of all systems required for coping with station blackout and for the time required to bring and maintain the plant in safe shutdown (non-design basis accident). Conversely, the EDGs are specifically designed to power design basis accident loads. Referring to the EDG nominal loads identified in the U.S. EPR FSAR Tier 2, Tables 8.3-4 through 8.3-7, it is apparent that most of the listed loads are associated with design basis accidents, and therefore separate load lists (refer to the U.S. EPR FSAR Tier 2, Tables 8.4-1 and 8.4-2) are required to identify the loads that are required for a station blackout non-design basis accident safe shutdown.

The reduced size of the alternate AC power source is directly attributable to the absence of design basis accident load on the alternate AC source.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.04-2:

Page 8.4-6 (8.4.2.1) of the FSAR includes the paragraph “Standby power system sources are not shared among nuclear units; thereby making sure an accident in one unit of a multiple-unit facility can be mitigated using an available compliment of features, including necessary ac power, irrespective of conditions in the other units and without giving rise to conditions unduly adverse to safety in another unit”, which appears addressing GDC-5 requirement. Evaluate whether the above sentence needs revision.

Response to Question 08.04-2:

The intent of this statement is to indicate that 10 CFR 50 Appendix A, Criterion 5 is not applicable to the U.S. EPR standby power system sources (four emergency diesel generators and two station blackout diesel generators), because these systems and their auxiliary units are designed to be independent of other neighboring nuclear units.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.04-3:

Page 8.4-12 (8.4.2.6.3) of the FSAR states that "U.S. EPR design provides two full capacity AAC power sources of diverse design, capable of powering at least one complete set of normal safe shutdown loads." Explain how engine, generator, and primary support equipment of SBODG and EDGs are diversely designed to avoid a common mode failure.

Response to Question 08.04-3:

Due to the large difference in nominal size between the station blackout diesel generators (SBODG) and the emergency diesel generators (EDG), the two types of diesel generator will be different models. As noted in the U.S. EPR FSAR Tier 2, Section 8.4.1.1, the two types of diesel generator are located in separate areas, and do not share control power, heating, ventilation, air conditioning, engine cooling, or fuel systems. The cooling system for the EDG transfers heat utilizing a water-to-water heat exchanger, while the corresponding system for the SBODG transfers heat from water-to-air through a radiator. There are no weather-related events or single active failures than can simultaneously disable the SBODGs and EDGs.

Specific diesel generator models have not yet been selected; therefore, comparison of specific engine, generator, or support system components is not possible at this time. However, the differences in size, location, and support systems minimize the probability of common mode failure.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

Question 08.04-4:

Page 8.4-13 (8.4.2.6.4) of the FSAR indicates “a COL applicant that references the U.S. EPR design certification will address the RG1.155 position C.3.4 related to procedures and training to cope with SBO.” Indicate in US-EPR that a COL applicant needs to submit the SBO coping procedures and training for the staff review to ensure that their plant conforms to the guidance in section C.3.4 to RG 1.155 and all required operator actions.

Response to Question 08.04-4:

The intent of combined license (COL) information items is to succinctly identify areas within the U.S. EPR FSAR Tier 2 where additional information must be provided or supplemented by the applicant. COL items are located within the U.S. EPR FSAR section where the information is to be provided or supplemented. However, the COL item descriptions are not intended to replicate or provide all the NRC guidance information from the SRP or RG 1.206 necessary for the applicant to satisfactorily address the COL item.

The current COL information item in the U.S. EPR FSAR Tier 2, Section 8.4.2.6.4, provides the necessary details to capture the applicant’s responsibilities for satisfactorily addressing the COL information item regarding procedures and training to cope with a station blackout.

FSAR Impact:

The U.S. EPR FSAR will not be changed as a result of this question.

U.S. EPR Final Safety Analysis Report Markups

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8.1.4.3 Criteria, Regulatory Guides, Standards, and Technical Positions

This section describes the design of the U.S. EPR power distribution system with respect to 10 CFR 50 Appendix A~~;~~, compliance to GDC, and conformance to listed RGs, IEEE Standards and NRC generic letters. The electric power systems design complies with regulatory requirements and conforms with regulatory guides and industry standards. ~~AREVA NP has taken no exceptions to regulatory guidance or industry standards for design of electrical systems for nuclear power plants.~~ Unless indicated as not applicable to the electrical distribution system, an item shown as acceptance criterion or that it is used as guidance indicates that the U.S. EPR is in compliance with the regulation or conformance with the guidance as indicated. Table 8.1-1—Acceptance Criteria and Guidelines Applicability for Electric Power Systems, provides a list of GDC, NRC Regulations, RGs, BTPs, NUREG Reports, SECYs and their applicability to the U.S. EPR electric power distribution system.

8.1.4.3.1 General Design Criteria

08.03.01-12

U.S. EPR compliance with GDC is addressed in Section 3.1. Details of compliance with GDC 2, GDC 4, GDC 5, GDC 17, GDC 18 and GDC 50 are described in Section 8.2.2, Section 8.3.1.2 or Section 8.3.2.2.

8.1.4.3.2 Regulatory Guides

See Table 8.1-1 for a list of NRC RGs and a list of the corresponding ~~DCD~~ FSAR sections for a description ~~to what extent~~of RG conformance ~~of the RG is shown~~.

8.1.4.3.3 IEEE Standards

As a minimum, these IEEE standards are implemented in the U.S. EPR electrical system design:

- IEEE Std 308-2001, "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."
  - Onsite power system meets the specifications of IEEE Std 308-2001 as endorsed by RG 1.32 and are addressed in Section 8.3.1.2.4 and Section 8.3.2.2.4.
- IEEE Std 317-2003, "IEEE Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations."
  - Containment electrical penetration assemblies meet the specifications of IEEE Std 317-2003 and are addressed in Section 8.3.1.2.7. For justification of using IEEE Std 317-2003 instead of IEEE Std 317-1983 as endorsed by RG 1.63, refer to Section 3.11.2.3.1.
- IEEE Std 338-1987, "IEEE Standard Criteria for the Periodic Surveillance Testing of Nuclear Power Generating Station Safety Systems."

Raceway and Cable Routing

Cable trays are arranged physically from top to bottom in accordance with the function and voltage class of the cables:

- 13.8 kV power cables.
- 6.9 kV power cables.
- Low voltage ~~ac~~AC and ~~dc~~DC power cables (480 Vac, 120 Vac, 250 Vdc, and 24 Vdc).
- Control cables (120 Vac, 250 Vdc, and 24 Vdc).
- Cables for low level analog and digital signals.

Power cables are installed in duct banks or raceways designed to provide a high level of protection against industrial hazards, long-term degradation, and other potential risks such as fire, missiles, pipe failure, water spray, or earthquakes.

Manholes for duct bank access have recesses for temporary sump pumps for water draining. Manholes located below the ground water line have a permanent sump pump design. Such areas are sloped so as to provide water drainage. Examples of cables that use underground duct ba~~e~~nks include cables for ~~ESW pump building~~the ESWPB, SBODG cables, offsite power cables from the EATs to the ~~Safeguards Building~~SB, and cables to the ~~Emergency Diesel Generator Building~~EPGB. Outdoor terminations are located in a NEMA 4X or better enclosure. Capability is provided to perform periodic test to detect insulation degradation in underground cables whether in a duct bank, directly buried or in a conduit, as described in NRC Generic Letter 2007-01 (Reference 13). One or more of the following testing methods can be used: partial discharge testing, time domain reflectometry, dissipation factor testing or very low frequency ~~ac~~AC testing.

08.03.01-12

Cable splices are not allowed in raceways or cable trays.

Distribution system switchgear are arranged to permit short cable connections between the switchgear and the loads in the lower part of the building via the cable floors, vertical cable risers and cable trays in the system rooms. The cables to the R~~eactor~~ B~~uilding~~ are routed via cable floors, the annulus, electrical containment penetrations, and cable trays in the R~~eactor~~ B~~uilding~~ system rooms.

The MV cables routed between divisions that provide the alternate feeds are routed in embedded conduit or concrete cable vault.

Cables originating in one division and routed to equipment in different divisions, or passing through a different division of the Safeguards Building are routed in the

Conformance with RG 1.6

The EPSS is designed in accordance with RG 1.6 to provide independence between the redundant standby power sources that supply the safety-related loads.

The EPSS has four divisions, normally powered from the preferred power source, each with an independent and redundant EDG assigned to their respective switchgear 31BDA, 32BDA, 33BDA, and 34BDA. The EPSS divisions combine to make two divisional pairs. Division 1 and 2 constitute the first divisional pair while divisions 3 and 4 constitute the second divisional pair. The EPSS safety-related loads are separated between the divisional pairs and a loss of one divisional pair will not prevent the minimum safety-related functions from being performed.

The four EPSS divisions are normally functionally independent and physically separated from each other. During periods a standby power source is out of service, or other similar maintenance activities, alternate feeds are provided between division 1 and division 2 or between divisions 3 and division 4 as appropriate for the out-of-service EDG. The alternate feed configuration, consistent with separating the safety-related loads between divisional pairs, maintains the plant capability to complete safety-related functions coincident with a single failure.

Alternate feeds have these features to provide independence between divisions:

- When required for maintenance or other operating conditions, the alternate feeds are manually implemented and have no automatic connections between divisions.
- The alternate feed incorporates an engineering design feature that prevents having two different divisional power sources supplying power to the same bus simultaneously. This prevents paralleling two EDGs.
- Alternate feed protection and coordination prevents a fault on one division from degrading the other division below an acceptable level.

Conformance with RG 1.9

The EDG mechanical and electrical design properties for starting and loading, including following light load or no load operation, have been incorporated so that they will start, accelerate to rated speed and properly sequence design loads while maintaining nominal frequency and voltage within limits specified in RG 1.9.

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The EDGs continuous load rating has been established utilizing the guidance in RG 1.9; specifically it is greater than the sum of the conservatively estimated connected loads that the EDG will power at any one time. In developing EDG load rating, performance characteristics for motors were calculated based on 90 percent efficiency, ~~MVA sizing developed using a~~and power factors of 85 percent or less. At least ten percent margin exists in each EDG to account for future load growth.

movement of this valve from isolating the accumulator when the accumulator is required to be operable, power is removed from the valve motor by opening its MCC ~~disconnect~~circuit breaker. This action is performed under administrative controls, and periodically verified in accordance with plant technical specification surveillance requirements as indicated in Chapter 16, Section 3.5.1.

Power is restored to the valve during applicable plant conditions by closing the MCC ~~disconnect~~circuit breaker. Capability to restore power is in accordance with BTP 8-4 (Reference 26), as operation of the valve is not required in the safety system operational sequence, and does not need to be rapidly restored during plant shutdown.

A redundant accumulator isolation valve position indication in the MCR is provided for verification of valve position.

BTP 8-5 Supplemental Guidance for Bypass and Inoperable Status Indication for Engineered Safety Features Systems

Additional guidance from BTP 8-5 (Reference 27) has been incorporated into the design of the bypassed and inoperable status indicators. Bypassed or inoperable status indicators are displayed as indicated in Section 7.5.2.

BTP 8-6 Adequacy of Station Electric Distribution System Voltages

Safety-related equipment is protected from degraded voltage conditions on Class 1E buses by a degraded voltage monitoring scheme. The degraded voltage setpoint and time delays are developed in accordance with BTP 8-6 (Reference 6) as described in Section 8.3.1.1.3.

Electrical analysis results will be verified by bus voltage measurements taken during tests conducted as described in Reference ~~25~~6 Section B.4. 08.03.01-12

BTP 8-7 Criteria for Alarms and Indications Associated with Diesel-Generator Unit Bypassed and Inoperable Status

The bypassed and inoperable status indications design for the EDGs conforms to the recommendations of ~~BTP 8-7 (~~Reference 28~~)~~; the design is described in Section 8.3.1.1.5.

8.3.1.3 Electrical Power System Calculations and Distribution System Studies for AC Systems

The electrical transient analyzer program (ETAP), nuclear version 5.5.6N, is utilized to analyze the ~~ac~~AC distribution system for load flow and voltage regulation, short-circuit studies and motor starting studies. ETAP has been qualified to 10 CFR Part 50 Appendix B, and also complies with 10 CFR 21, ASME NQA-1 (Reference 29), ISO 9001 (Reference 30), and IEEE Std 730.1-1989 (Reference 31).

Plant structures, fences, tanks, switchgear, load centers, MCCs, motors, switch mats and cable trays are bonded to the station ground grid with two ground conductors and each conductor is bonded to the station ground grid in at least two places.

Electrical grounds for the ground bus of all switchgear assemblies, MCCs and load centers are bonded to the station ground grid in at least two places.

Each building is equipped with its own grounding system, which is connected to the station ground grid. Individual building steel support columns and re-bar mesh are bonded to the station ground grid.

The main generator, EDG and SBODG neutrals are high resistance grounded using a distribution transformer method. The station auxiliary transformers high voltage winding neutral point is directly grounded to the station ground grid. The neutral for the low voltage windings are grounded using a neutral grounding resistor.

The MV transformer secondary winding neutrals are connected to the ground system through a resistance. This grounding method provides proper detection and isolation of phase-to-ground faults.

Low voltage distribution transformer secondary windings are solidly grounded.

The isolated phase bus (IPB) is electrically continuous with three phase enclosures bonded together at the generator end and at the transformer end. The IPB is grounded at a single point at the MSU end, which limits circulating currents. The bus enclosures are electrically insulated from the support structures and adjoining equipment. IPB supports located inside the turbine building are connected to the building ground grid. Outdoor supports are grounded by connecting the base of each support to the ground grid with two grounding conductors bonded to the ground grid in two locations.

Plant instrumentation is grounded through a separate radial grounding system consisting of isolated instrumentation ground buses and insulated cables. The instrumentation grounding systems are connected to the station grounding grid at one point only and are insulated from all other grounding circuits. I&C systems are grounded in accordance with Reference ~~16 as described in Section 7.1~~17. 08.03.01-12

The ~~dc~~DC system is operated as an ungrounded system. Ground detection is described in Section 8.3.2.3.7.

8.3.2 DC Power Systems

8.3.2.1 Description

The ~~dc~~DC power system includes a Class 1E UPS (EUPS) system, a non-Class 1E 12-hour UPS (12UPS) system and a non-Class 1E UPS (NUPS) system. In general, the

between these non-Class 1E circuits and Class 1E circuits in accordance with Reference 10 as described in Section 8.3.1.1.9.

The EUPS supplies assigned loads during normal and off-normal operation, including when onsite ~~ac~~AC power is not available and during the starting phase of the EDGs when the battery charger ~~ac~~AC input power is lost. During loss of power to the battery charger, the EUPS loads are powered from the battery via the ~~dc~~DC distribution switchboard or inverters until the battery charger has been re-powered from the EDGs. Both battery chargers in division 1 and 4 are capable of being supplied by the SBODG. The battery charger supplied from 32BMB and 33BMB in division 2 and 3 respectively are also capable of being powered from the SBODGs.

The EUPS system components have local battery charger and inverter indications to permit system monitoring. DC switchboard and 480 Vac MCC voltage, battery charger output current and battery charge or discharge rate are indicated in the MCR and RSS. A ~~dc~~DC switchboard undervoltage alarm indicates the battery is being discharged and a ~~dc~~DC system ground alarm is provided in the MCR.

8.3.2.1.1.2 250 V~~DC~~dc Batteries

The EUPS battery cells are the vented (flooded) lead-acid type. The battery is immediately available during normal operation and following the loss of power from the ~~ac~~AC power system. Each battery is able to provide power for starting and operating DBE loads for a minimum of two hours when the ~~ac~~AC supply to the battery charger is lost.

The battery voltage profile during the first two hours of discharge provides satisfactory operation of safety-related electrical loads during postulated DBE conditions.

Each EUPS divisional battery is located in a ventilated battery room that is separated from other EUPS equipment. The electrical division of the safeguard building ventilation system (SBVS) prevents accumulation of hydrogen and maintains design battery temperature. Hydrogen buildup is limited to one percent of the total volume of the battery area in accordance with RG 1.128. The battery ventilation supplied by the electrical division of SBVS is described in Section 9.4.6.

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The EUPS battery installation design is in accordance with IEEE Std 484-2002 (Reference ~~36~~37) as augmented by RG 1.128. The EUPS batteries are qualified in accordance with IEEE Std 535-1986 (Reference 38) as endorsed by RG 1.158.

The ~~dc~~DC portion of the EUPS system is operated as an ungrounded system.

During normal EPSS bus alignments, four redundant divisions are physically separated and electrically independent preventing failure in one division from having a detrimental affect on another division that would prevent performance of a safety function. Each EUPS division contains a battery and battery charger. There are no automatic or manual connections between EUPS divisions.

Conformance with RG 1.32

The EUPS batteries, battery chargers, inverters and distribution equipment are designed to provide sufficient power at the quality necessary for the safety systems to meet their functional requirements as described by Reference 3, as endorsed by RG 1.32.

Conformance with RG 1.75

Each EUPS division is located in separate Seismic Category 1 Safeguards Buildings and Diesel Buildings. This arrangement provides physical separation through the use of safety class structures for the majority of the electrical equipment and circuits. Cable routing, derating, raceway fill, separation, and identification of redundant Class 1E circuits and~~,~~ isolation of non-Class 1E circuits from Class 1E circuits is in accordance with Reference ~~9~~10, as supplemented by RG 1.75.

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Cable routing, including cable derating and cable tray fill criteria, is described in Section 8.3.1.1.8.

Cable independence and separation is described in Section 8.3.1.1.9.

Conformance with RG 1.128

Initial design and installation of EUPS batteries meet the criteria of Reference 37, as supplemented by RG 1.128, for proper design and installation for large lead-acid storage batteries.

Conformance with RG 1.129

Maintenance and testing of EUPS batteries is in accordance with IEEE Std 450-2002 (Reference 39), as supplemented by RG 1.129. Battery surveillance testing is described in the technical specifications detailed in Chapter 16.

Conformance with RG 1.153

The electrical power functions of the power, instrumentation, and control portions of safety systems are designed in accordance with Reference 1, which meets or exceeds the requirements of ~~IEEE Std 603-1991 (~~Reference 40~~)~~, as endorsed by RG 1.153.

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Table 8.3-9—Onsite AC Power System Failure Modes and Effects Analysis
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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
1	Main generator	Provides power to the transmission system and the EATs and NATS through the switchyard.	Fault or failure in the main generator or main turbine	Fault or failure in the main generator, or main turbine that results in main generator or main turbine trip.	None, system does not have a safety-related function.	Alarms in the MCR	a. Main generator is tripped and MSUs are isolated by protective relays. b. Turbine trip is initiated. c. Offsite power sources remain in service.
2	Main step-up transformer 30BTA01, 30BTA02, or 30BTA03	Transforms main generator output voltage to offsite transmission system voltage and transmits main generator output to the switchyard.	Fault or failure in the MSU	Internal or external fault.	None, system does not have a safety-related function.	Alarms in the MCR	a. Main generator is tripped and MSUs are isolated by protective relays. b. Turbine trip is initiated. c. Offsite power sources to NPSS nad EPSS switchgear remain in service.
3	Main step-up transformer cooling	Provides MSU cooling.	Loss of cooling	Failure of pumps or cooling fans.	None, system does not have a safety-related function.	Alarms in the MCR	a. Failure of group of pumps or cooling fans will leave remaining pumps and cooling fans unaffected. b. Main generator output reduction to within remaining cooling capability is necessary.
4	Isolated phase bus duct	Transfers power from the main generator to the MSUs.	Bus failure	Bus failure, including failure of bus supports or insulators.	None, system does not have a safety-related function.	Alarms in the MCR	a. IPB, MSU and generator are isolated by protective relays, which cause main generator output breakers located in switchyard to trip. b. Turbine trip is initiated. c. Offsite power sources to NPSS and EPSS switchgear remain in service.
5	Isolated phase bus duct cooling	Provides forced air cooling for the IPB.	Loss of cooling	Failure of the IPB cooling system including loss of cooling heat sink.	None, system does not have a safety-related function.	Alarms in the MCR	a. Standby fan will auto start on fan failure. b. Loss of closed cooling water or loss of forced air circulation will require main generator output reduction to maintain temperature within the IPB ratings.
6	Normal auxiliary transformer 30BBT01, 30BBT02 or 30BBT03	Supplies power from switchyard to the NPSS 13.8 kV switchgear.	Transformer failure	Fault, including internal fault resulting in sudden pressure or overcurrent.	None, system does not have a safety-related function.	Alarms in the MCR	a. Faulted transformer is isolated by protective relaying. b. Transformer failure initiates a fast transfer of affected NPSS buses to alternate source NAT.

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Table 8.3-9—Onsite AC Power System Failure Modes and Effects Analysis
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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
7	Normal auxiliary transformer cooling	Provides cooling to the NAT.	Loss of transformer cooling	Loss of one or both sets of fans due to loss of operating power, fan failure, or cable failure.	None, system does not have a safety-related function.	Alarms in the MCR	a. Normal alignment has transformer loading within transformer self-cooling ratings, so there are no immediate actions required. b. Should transformer also be carrying the alternate loads, high temperature alarm provides indication to transfer loads if necessary. Excessively high temperature beyond the NAT alarm level will cause that NAT to trip from service, causing possible reactor and turbine trip, or plant power reduction or shutdown as a result of de-energized balance of plant loads. c. Loading on the affected NAT is manually transferred to the remaining NATs.
8	Emergency auxiliary transformer 30BDT01 or 30BDT02	Supplies power from the switchyard to the EPSS 6.9 kV switchgear.	Transformer failure	Fault, including internal fault resulting in sudden pressure or overcurrent.	None, system does not have a safety-related function.	Alarms in the MCR	a. Faulted transformer is isolated by protective relaying. b. Transformer failure initiates a fast transfer of affected EPSS buses to alternate source EAT.
9	Emergency auxiliary transformer cooling	Provides cooling to the EAT.	Loss of transformer cooling	Loss of one or both sets of fans due to loss of operating power, fan failure or cable failure.	None, system does not have a safety-related function.	Alarms in the MCR	a. Normal alignment has transformer loading within transformer self-cooling rating, so there are no immediate actions required. b. Should transformer also be carrying the alternate loads, high temperature alarm provides indication to transfer loads if necessary. Excessively high temperature beyond the EAT alarm level will cause that EAT to trip from service. c. EAT trip while carrying all four EPSS divisions will cause loss of power to each division and subsequent EDG start and loading onto the affected buses.
10	13.8 kV bus duct that exists between NATs and the 13.8 kV NPSS switchgear 31BBA, 32BBA, 33BBA, 34BBA, 35BBA or 36BBA	Provides connection between the NATS and the 13.8 kV NPSS switchgear.	Bus duct fault	Bus duct fault or failure.	None, system does not have a safety-related function.	Alarms in the MCR	a. A fault on the bus duct will result in isolation of the affected transformer by protective relaying. b. The source breaker to the affected NPSS switchgear 31BBA, 32BBA, 33BBA, 34BBA, 35BBA, or 36BBA operates and isolates the transformer. c. Transformer failure initiates a fast transfer of the affected buses.

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Table 8.3-9—Onsite AC Power System Failure Modes and Effects Analysis
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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
11	13.8 kV NPSS switchgear primary source breaker from NATs to switchgear 31BBA, 32BBA, 33BBA, 34BBA, 35BBA or 36BBA	Provides primary point of isolation for 13.8 kV buses 31BBA, 32BBA, 33BBA, 34BBA, 35BBA, or 36BBA from NATs.	Breaker failure or fault	Breaker failure resulting in breaker tripping.	None, system does not have a safety-related function.	Alarms in the MCR	a. The faulted breaker is isolated by protective relaying; the affected 13.8 kV switchgear bus and all downstream buses are de-energized. b. SBODGs will re-energize 31BBH or 32BBH if necessary. c. The affected and unfaulted bus can be manually transferred to its alternately assigned NAT source. d. Possible reactor or turbine trip, or plant power reduction or shutdown as a result of lost balance of plant loads.
12	NPSS 13.8 kV switchgear 31BBA, 32BBA, 33BBA, 34BBA, 35BBA or 36BBA	Transfer power from the NATs to the NPSS loads in the respective train.	Loss of voltage	Bus fault or failure.	None, system does not have a safety-related function.	Alarm in the MCR	a. The faulted bus is isolated by protective relaying; the affected 13.8 kV switchgear bus source breakers are tripped and locked out. b. Downstream buses are de-energized. c. Possible reactor or turbine trip, or plant power reduction or shutdown as a result of de-energized balance of plant loads. d. SBODGs will re-energize 31BBH or 32BBH if necessary.
13	Feeder breaker from NPSS bus 31BBA, 32BBA, 33BBA, or 34BBA to the source breaker on 31BBC, 32BBC, 33BBC or 34BBC Or the source breaker on NPSS bus 31BBC, 32BBC, 33BBC or 34BBC	Connect BBA bus to the respective BBC bus.	Breaker failure	Breaker failure resulting in breaker tripping.	None, redundant RCP trip function is unaffected.	Alarm in the MCR	a. Faulted breaker is isolated by protective relaying; the affected 13.8 kV switchgear bus 31BBC, 32BBC, 33BBC, or 34BBC and downstream buses are de-energized. b. Respective RCP is de-energized, resulting in plant shutdown as required by technical specifications. c. The RCP trip function remains available with the RCP breaker.
14	NPSS distribution transformers 31BBT08 or 32BBT08	Transforms 31BBA or 32BBA 13.8 kV power to 6.9 kV power for 31BBH and 32BBH respectively.	Transformer failure	Transformer fault including short circuit.	None, system does not have a safety-related function.	Alarm in the MCR	a. Protective relaying isolates faulted transformer. b. Respective 31BBH or 32BBH is de-energized. c. Respective SBODG starts and re-powers the 31BBH or 32BBH switchgear.

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Table 8.3-9—Onsite AC Power System Failure Modes and Effects Analysis
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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
15	NPSS 6.9 kV 31BBH or 32BBH switchgear	Supply NUPS and 12UPS battery chargers. Provides connection point for SBODGs to the NPSS.	Bus failure	Bus fault including short circuit.	None, system does not have a safety-related function.	Alarm in the MCR	a. Protective relaying isolates faulted switchgear; source breakers are tripped and locked out. b. 31BBH or 32BBH and downstream buses are de-energizing. c. NUPS and 12UPS standby battery chargers can be placed in service for affected trains. d. SBODG unavailable for affected bus.
16	NPSS distribution transformers 31BFT08 or 32BFT08	Transforms 31BBH or 32BBH 6.9 kV power to 480 Vac for 31BFX and 32BFX respectively.	Transformer failure	Transformer fault, including short circuit.	None, system does not have a safety-related function.	Alarm in the MCR	a. Protective relaying isolates faulted transformer. b. 31BFX or 32BFX and downstream buses are de-energizing. c. NUPS and 12UPS standby battery chargers can be placed in service for affected trains. d. Affected SBODG auxiliaries are de-energized resulting in the supported SBODG being unavailable.
17	NPSS 480 Vac load centers 31BFX or 32BFX	Supplies NUPS and 12UPS battery chargers; feeds MCCs 31BHZ01, 32BHZ01 which supply SBODG auxiliaries.	Bus failure	Bus fault including short circuit.	None, system does not have a safety-related function.	Alarm in the MCR	a. Protective relaying isolates faulted load center; source breaker is tripped and locked out. b. 31BFX or 32BFX and downstream buses are de-energizing. c. NUPS and 12UPS standby battery chargers can be placed in service for affected trains. d. Affected SBODG auxiliaries are de-energized resulting in the supported SBODG being unavailable.
18	6.9 kV power cable between either EAT and the EPSS switchgear 31BDA, 32BDA, 33BDA or 34BDA	Transfer power from the EATs to the EPSS loads in the respective division.	Cable or cable duct fault	Cable or cable duct fault including short circuit or ground fault.	None, power feed from the EAT to the EPSS switchgear does not have a safety-related function.	Alarms in the MCR	a. Protective relaying isolates the affected power cable and transformer. b. Fast transfer of the affected buses is initiated by EAT ~~differential transfer relay~~failure.
19	6.9 kV safety-related switchgear primary source breaker from EATs to switchgear 31BDA, 32BDA, 33BDA, or 34BDA	Provides primary point of isolation of 6.9 kV switchgear from EATs.	Breaker failure or fault	Breaker failure resulting in breaker tripping.	None, safety-related function is maintained by redundant divisions.	Alarms in the MCR	a. The faulted breaker is isolated by protective relaying; the affected 6.9 kV switchgear bus and downstream buses are de-energized. b. The respective division EDG starts and automatically re-energizes the affected buses. c. The EDG can be paralleled with the alternate source EAT to transfer EPSS loads.

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Table 8.3-9—Onsite AC Power System Failure Modes and Effects Analysis
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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
20	EPSS 6.9 kV safety-related switchgear 31BDA, 32BDA, 33BDA, or 34BDA	Powers 6.9 kV EPSS loads and transfers power from the EATs to the rest of the EPSS buses in each division.	Bus failure	Bus fault, including short circuit.	None. Safety-related function is maintained by redundant divisions.	Bus undervoltage alarm in the MCR	a. Protective relay operation trips and locks out the bus source breakers and load breakers. b. Affected bus and downstream buses are de-energized. c. Respective division EDG will start but will not energize the faulted bus due to the EDG output breaker lock out.
21	EPSS 6.9 kV safety-related switchgear 31BDB, 31BDC, 31BDD, 32BDB, 32BDD, 33BDB, 33BDD, 34BDB, 34BDC or 34BDD	Powers 6.9 kV EPSS loads and transfers power to EPSS 480 Vac buses in each division.	Bus failure	Bus fault, including short circuit.	None. Safety-related function is maintained by redundant divisions.	Bus undervoltage alarm in the MCR	a. Protective relay operation trips and locks out the bus source breaker. b. Affected bus and downstream buses are de-energized.
22	EPSS distribution transformers 31BMT01, 31BMT02, 31BMT03, 31BMT04, 32BMT01, 32BMT02, 32BMT04, 33BMT01, 33BMT02, 33BMT04, 34BMT01, 34BMT02, 34BMT03 or 34BMT04	Transforms 6.9 kV from switchgear to 480 Vac for load center and MCC loads.	Transformer failure	Transformer fault, including short circuit.	None. Safety-related function is maintained by redundant divisions.	Supplied bus undervoltage alarm in the MCR	a. Protective relaying isolates the faulted transformer, de-energizing down steam loads.
23	6.9 kV feeder cable between EPSS 6.9 kV switchgear bus and distribution transformer or load center	Supplies power from 6.9 kV switchgear to EPSS distribution transformers and load centers.	Cable failure	Cable fault, including short circuit.	None. Safety-related function is maintained by redundant divisions.	Bus undervoltage alarm in the MCR	a. Protective relaying isolates the faulted cable, de-energizing down stream loads.
24	EPSS load centers: 31BMA, 31BMB, 31BMC, 31BMD, 32BMA, 32BMB, 32BMD, 33BMA, 33BMB, 33BMD, 34BMA, 34BMB. 34BMC or 34BMD	Supplies power to large EPSS 480 Vac loads and MCCs.	Load center failure	Load center failure such as bus failure, including short circuit.	None. Safety-related function is maintained by redundant divisions.	Bus undervoltage alarm in the MCR	a. Protective relaying trips and locks out load center source breaker, de-energizing down stream loads.
25	480 Vac feeder cable between EPSS load center and MCC	Supplies power to EPSS MCCs.	Cable failure	Cable fault, including short circuit.	None. Safety-related function is maintained by redundant divisions.	Bus undervoltage alarm in the MCR	a. Protective relaying isolates the faulted cable, de-energizing down stream loads.

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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
26	480 Vac EPSS MCCs: 31BNA01, 31BNA02, 31BNB01, 31BNB02, 31BNB03, 31BNC01, 31BND01, 32BNA01, 32BNA02, 32BNB01, 32BNB02, 32BNB03, 32BND01, 33BNA01, 33BNA02, 33BNB01, 33BNB02, 33BNB03, 33BND01, 34BNA01, 34BNA02, 34BNB01, 34BNB02, 34BNB03, 34BNC01 or 34BND01	Supplies power to smaller EPSS 480 Vac loads.	MCC failure	MCC bus fault, including short circuit.	None. Safety-related function is maintained by redundant divisions.	Bus undervoltage alarm in the MCR	a. Protective relaying trips and locks out faulted MCC source breaker, de-energizing down stream loads.
27	Voltage regulating transformer 31BNT01, 32BNT01, 33BNT02 or 34BNT01	Provides regulated voltage to: 31BNB02, 31BNB03, 32BNB02, 32BNB03, 33BNB02, 33BNB03, 34BNB02 or 34BNB03 Inverter static switch bypass source for 31BRU01, 32BRU01, 33BRU01, 34BRU01.	Transformer failure	Transformer failure including failure to regulate voltage, or short circuit.	None. Safety-related function is maintained by redundant divisions.	Bus undervoltage alarm in the MCR	a. Failure to regulate voltage results in voltage levels below that necessary to start and accelerate motors during EDG loading sequence. Safety-related functions are completed with redundant equipment for any motors that do not start. b. Protective relaying isolates affected transformer, de-energizing downstream loads. c. EUPS inverter static switch bypass source is unavailable.
28	Emergency diesel generators: division 1 EDG, division 2 EDG, division 3 EDG or division 4 EDG	Supplies standby power to EPSS switchgear 31BDA, 32BDA, 33BDA or 34BDA in the event of loss of power to the respective bus.	EDG failure while operating in the emergency mode	EDG failure.	None. Safety-related function is maintained by redundant divisions.	Alarm in the MCR	a. EDG output breaker is tripped with the EDG trip. b. EPSS 6.9 kV switchgear and downstream buses are de-energized. c. Bus is available to be re-powered from normal offsite power source.

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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
29	EPSS division 1 switchgear, load centers and MCCs, while being fed by alternate feed from division 2	Supplies power to safety-related loads during normal conditions and DBEs.	EDG failure while operating in the emergency mode.	EDG failure.	None. Safety-related function is maintained by redundant divisions.	Alarm in the MCR	An EDG trip while operating in the emergency mode when the redundant EDG in the divisional pair is out of service and the alternate feed is implemented is assumed worst case condition during DBA and LOOP, as the most equipment is affected. a. EDG 1 assumed out of service at start of following two different transients. b. EDG 2 trip will cause loss of power to EPSS buses in divisions 1 and 2. EUPS loads in divisions 1 and 2 are powered from the battery for two hours. Redundant EDGs and safety-related loads in divisions 3 and 4 have capacity and capability to perform required safety-related functions. c. EDG 3 or EDG 4 trip will cause loss of power to affected division EPSS buses. EUPS loads in affected division are powered from the battery for two hours. EDG 2 and required redundant safety-related loads in divisions 1 and 2 have capacity and capability to perform required safety-related functions.

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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
30	EPSS division 2 switchgear, load centers and MCCs, while being fed by alternate feed from division 1	Supplies power to safety-related loads during normal conditions and DBEs.	EDG failure while operating in the emergency mode.	EDG failure.	None. Safety-related function is maintained by redundant divisions.	Alarm in the MCR	An EDG trip while operating in the emergency mode when the redundant EDG in the divisional pair is out of service and the alternate feed is implemented is assumed worst case condition during DBA and LOOP, as the most equipment is affected. a. EDG 2 assumed out of service at start of following two different transients. b. EDG 1 trip will cause loss of power to EPSS buses in divisions 1 and 2. EUPS loads in divisions 1 and 2 are powered from the battery for two hours. Redundant EDGs and safety-related loads in divisions 3 and 4 have capacity and capability to perform required safety-related function. c. EDG 3 or EDG 4 trip will cause loss of power to affected division EPSS buses. EUPS loads in affected division are powered from the battery for two hours. EDG 1 and required redundant safety-related loads in divisions 1 and 2 have capacity and capability to perform required safety-related functions.

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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
31	EPSS division 3 switchgear, load centers and MCCs, while being fed by alternate feed from division 4	Supplies power to safety-related loads during normal conditions and DBEs.	EDG failure while operating in the emergency mode.	EDG failure.	None. Safety-related function is maintained by redundant divisions.	Alarm in the MCR	An EDG trip while operating in the emergency mode when the redundant EDG in the divisional pair is out of service and the alternate feed is implemented is assumed worst case condition during DBA and LOOP, as the most equipment is affected. a. EDG 3 assumed out of service at start of following two different transients. b. EDG 4 trip will cause loss of power to EPSS buses in divisions 3 and 4. EUPS loads in divisions 3 and 4 are powered from the battery for two hours. Redundant EDGs and safety-related loads in divisions 1 and 2 have capacity and capability to perform required safety-related functions. c. EDG 1 or EDG 2 trip will cause loss of power to affected division EPSS buses. EUPS loads in affected division are powered from the battery for two hours. EDG 4 and required redundant safety-related loads in divisions 3 and 4 have capacity and capability to perform required safety-related functions.

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Item No.	Component Identification	Function	Failure Mode	Failure Mechanism	Effect on System Safety-Related Function	Method of Failure Detection	Remarks
32	EPSS division 4 switchgear, load centers and MCCs, while being fed by alternate feed from division 3	Supplies power to safety-related loads during normal conditions and DBEs.	EDG failure while operating in the emergency mode.	EDG failure.	None. Safety-related function is maintained by redundant divisions.	Alarm in the MCR	An EDG trip while operating in the emergency mode when the redundant EDG in the divisional pair is out of service and the alternate feed is implemented is assumed worst case condition during DBA and LOOP, as the most equipment is affected. a. EDG 4 assumed out of service at start of following two different transients. b. EDG 3 trip will cause loss of power to EPSS buses in divisions 3 and 4. EUPS loads in divisions 3 and 4 are powered from the battery for two hours. Redundant EDGs and safety-related loads in divisions 1 and 2 have capacity and capability to perform required safety-related functions. c. EDG 1 or EDG 2 trip will cause loss of power to affected division EPSS buses. EUPS loads in affected division are powered from the battery for two hours. EDG 3 and required redundant safety-related loads in divisions 3 and 4 have capacity and capability to perform required safety-related functions.

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