U.S. NUCLEAR REGULATORY COMMISSION

DESIGN-SPECIFIC REVIEW STANDARD for NuScale SMR DESIGN

8.2 OFFSITE POWER SYSTEM

REVIEW RESPONSIBILITIES

Primary - Organization Responsible for Electrical Engineering Review

Secondary - None

I. AREAS OF REVIEW

The descriptive information, analyses, and referenced documents, including electrical single-line diagrams, electrical schematics, logic diagrams, tables, and physical arrangement drawings for the offsite power systems, presented in the applicant's safety analysis report, are reviewed. The objective of the review is to determine that this system satisfies the requirements of Title 10 of the *Code of Federal Regulations* (CFR) Part 50, Appendix A, General Design Criteria (GDC) 5, 17, and 18, and will perform its design functions during all plant operating and accident conditions. The offsite power system is referred to in industry standards and regulatory guides (RGs) as the "preferred power system." The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources and encompasses the grid, transmission lines (overhead or underground), transmission line towers, transformers, switchyard components and control systems, switchyard battery systems, the main generator, generator circuit breakers or load break switches (if provided), disconnect switches, and other switchyard equipment, such as capacitor banks and volt amperes reactive (VAR) compensators, provided to supply electric power to safety-related and other equipment.

The specific areas of review are as follows:

1. The preferred power system arrangement is reviewed to determine that the required minimum of two separate circuits from the transmission network to the onsite distribution system is provided. In determining the adequacy of this system, the independence of the two (or more) circuits is examined to see that both electrical and physical separation exist, so as to minimize the chance of simultaneous failure. This includes a review of the assignment of power sources from the grid; location of rights-of-way, transmission lines and towers, transformers, switchyard interconnections (breakers and bus arrangements), switchyard control systems, and power supplies; and location of switchgear (in-plant), interconnections between switchgear, cable routings, main generator disconnect, the disconnect control system and power supply, and generator circuit breakers and load break switches.

2. The independence of the preferred power system is evaluated with respect to the onsite power system. The scope of review extends to the safety-related distribution system buses that are capable of being powered by standby power sources. It does not include the supply breakers of the safety-related distribution system buses. This evaluation will include a review of the electrical protective relaying and breaker control circuits and

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power supplies to ensure that the loss of one preferred system circuit will not cause or result in the loss of any required redundant counterpart, nor any standby power source.

3. Design information and analyses demonstrating the suitability of the power sources from the grid, including transmission lines, breakers, and transformers used for supplying preferred power from distant sources, are reviewed to ensure that each path has sufficient capacity and capability to perform its intended function. This will require examination of loads required to be powered for each plant operating condition; continuous and fault ratings of breakers, transformers, and transmission lines; loading, unloading, and transfer effects on equipment; and power capacity available from each source.

4. The instrumentation required for monitoring and indicating the status of the preferred power system is reviewed to ensure that any change in the preferred power system that would prevent it from performing its intended function will be immediately identified by the control room operator. Also, all instrumentation for initiating safety actions associated with the preferred power system is reviewed.

5. The capability to test the preferred power system is reviewed.

6. Environmental conditions such as those resulting from high and low atmospheric temperatures, high wind, rain, lightning discharges, snow, and ice are considered in the review of the preferred power system to determine any effects on function.

7. Quality group classifications of equipment of the preferred power system are reviewed.

8. The interface(s) of the preferred power system with the alternate alternating current (AAC) power source(s), if provided, is reviewed. The design, operation, and performance of the AAC power source(s) are reviewed in accordance with Design-Specific Review Standard (DSRS) Section 8.4.

9. Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC). For design certification (DC) and combined license (COL) reviews, the staff reviews the applicant's proposed ITAAC associated with the structures, systems, and components (SSCs) related to this DSRS section in accordance with SRP Section 14.3.6, "Electrical Inspections, Tests, Analyses, and Acceptance Criteria," and NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (SRP) Section 14.3, "Inspections, Tests, Analyses, and Acceptance Criteria." The staff recognizes that the review of ITAAC cannot be completed until after the rest of this portion of the application has been reviewed against acceptance criteria contained in this DSRS section. Furthermore, the staff reviews the ITAAC to ensure that all SSCs in this area of review are identified and addressed as appropriate, in accordance with SRP Sections 14.3.and 14.3.6.

10. COL Action Items and Certification Requirements and Restrictions. For a DC application, the review will also address COL action items and requirements and restrictions (e.g., interface requirements and site parameters).

11. For a COL application referencing a DC, a COL applicant must address COL action items (referred to as COL information in certain DCs) included in the referenced DC. Additionally, a COL applicant must address requirements and restrictions (e.g., interface requirements and site parameters) included in the referenced DC.

Review Interfaces

Other SRP and DSRS sections interface with this section as follows:

1. The organization responsible for electrical engineering reviews the adequacy of the onsite power system, including station batteries and associated dc systems, and associated instrumentation and control systems, as part of its primary review responsibility for DSRS Sections 8.3.1 and 8.3.2.

2. The organization responsible for electrical engineering reviews the overall compliance with 10 CFR 50.63 requirements, as part of its primary review responsibility for DSRS Section 8.4

3. The organization responsible for the review of reactor systems determines those system components requiring electric power as a function of time for each mode of reactor operation and accident condition as part of its primary review responsibility for DSRS Section 6.3, and SRP Sections 4.6 and 5.4.12.

4. The organization responsible for the review of plant systems determines those system components requiring electric power as a function of time for each mode of reactor operation and accident condition as part of its primary review responsibility for DSRS Sections 9.1.3 and 10.4.7, and SRP Sections 9.1.4, 9.2.1, 9.2.2, 9.2.4, 9.2.5, 9.2.6, 9.3.1, 9.3.3, 9.4.1, 9.4.2, 9.4.3, 9.4.4, 9.5.1.1, 9.5.1.2, and 10.4.5.

5. The organization responsible for the review of plant systems also verifies, on request, the adequacy of those auxiliary systems required for the proper operation of the preferred power system. These include such systems as heating and ventilation systems for switchgear in the circuits from the preferred power sources to the onsite power distribution system buses and main generator auxiliary systems, such as the cooling water system, hydrogen cooling system, turbine electro-hydraulic control system, and air supply system.

6. The organization responsible for the review of plant systems verifies, on request, the physical arrangements of components and structures of the preferred power system to ensure that the paths from the preferred power sources to the standby power distribution system buses will not experience simultaneous failure under operating or postulated accident environmental conditions. This includes the effects of floods, missiles, pipe whipping, and discharging fluids that result from equipment failures.

7. The organization responsible for the review of plant systems examines fire detection and firefighting systems in preferred power system areas to ensure that the adverse effects of fire are minimized as part of its primary review responsibility for SRP Sections 9.5.1.1 and 9.5.1.2. The plant systems review includes evaluation of the adequacy of fire protection provided for redundant power supplies and circuits.

8. The organization responsible for the review of materials and chemical engineering determines those system components requiring electric power as a function of time for each mode of reactor operation and accident condition as part of its primary review responsibility for SRP Sections 9.3.2 and DSRS Section 9.3.4.

9. The organization responsible for civil engineering and geosciences review provides, on request, the information necessary to assess the effects of environmental conditions (i.e., high and low atmospheric temperature, high winds, rain, ice, and snow) on the preferred power system.

10. The organization responsible for the review of technical specifications (TS) coordinates and performs reviews of TS as part of its primary review responsibility for DSRS Section 16.0.

11. The organization responsible for the review of containment systems and severe accidents determines those system components requiring electric power as a function of time for each mode of reactor operation and accident condition as part of its primary review responsibility for DSRS Sections 6.2.2, 6.2.4, and 6.2.5.

12. The organization responsible for the quality assurance (QA) review determines the acceptability of the preoperational and initial startup tests and programs as part of its primary review responsibility for DSRS Section 14.2.

13. The organization responsible for human factors reviews the adequacy of administrative, testing, and operating procedure programs as part of its primary review responsibility for SRP Sections 13.5.1.1, 13.5.2.1, and 13.5.2.2.

14. The organization responsible for QA reviews the design, construction, and operation phases of the QA programs under SRP Chapter 17. In addition, while conducting regulatory audits in accordance with Office Instruction NRR-LIC-111 or NRO-REG-108, "Regulatory Audits," the technical staff may identify quality-related issues. If this occurs, then the technical staff should contact the organization responsible for QA to determine if an inspection should be conducted.

15. The organization responsible for the review of the probabilistic risk assessment performs the review to address the potential risk significance of SSCs.

II. ACCEPTANCE CRITERIA

Requirements

In general, the preferred power system is acceptable when it can be concluded that two separate circuits from the transmission network to the onsite Class 1E power distribution system are provided, adequate physical and electrical separation exists, and the system has the capacity and capability to supply power to all safety loads and other required equipment.

Table 8-1 of DSRS Section 8.1 lists GDC, RGs, standards, and branch technical positions (BTPs) used as the bases for arriving at this conclusion.

Acceptance criteria are based on meeting the relevant requirements of the following Commission regulations:

1. GDC 5, "Sharing of Structures, Systems, and Components"

2. GDC 17, "Electric Power Systems"

3. GDC 18, "Inspection and Testing of Electric Power Systems"

4. GDC 33, "Reactor Coolant Makeup"; GDC 34, "Residual Heat Removal"; GDC 35, "Emergency Core Cooling"; GDC 38, "Containment Heat Removal"; GDC 41, "Containment Atmosphere Cleanup"; and GDC 44, "Cooling Water"

5. 10 CFR 50.65(a)(4), as it relates to the assessment and management of the increase in risk that may result from proposed maintenance activities before the maintenance activities are performed. These activities include, but are not limited to, surveillances, post-maintenance testing, and corrective and preventive maintenance. Compliance with the maintenance rule, including verification that appropriate maintenance activities are covered therein, is reviewed under SRP Chapter 17. Programs for incorporation of requirements into appropriate procedures are reviewed under SRP Chapter 13.

6. 10 CFR 52.47(b)(1), which requires that a DC application contain the proposed ITAAC that are necessary and sufficient to provide reasonable assurance that, if the inspections, tests, and analyses are performed and the acceptance criteria met, a facility that incorporates the DC is has been constructed and will be operated in conformity with the DC, the provisions of the Atomic Energy Act (AEA), and the U.S. Nuclear Regulatory Commission's (NRC's) regulations

7. 10 CFR 52.80(a), which requires that a COL application contain the proposed inspections, tests, and analyses, including those applicable to emergency planning, that the licensee shall perform, and the acceptance criteria that are necessary and sufficient to provide reasonable assurance that, if the inspections, tests, and analyses are performed and the acceptance criteria met, the facility has been constructed and will operate in conformity with the COL, the provisions of the AEA, and the NRC's regulations

DSRS Acceptance Criteria

Specific DSRS acceptance criteria that meet the relevant requirements of the NRC's regulations identified above are set forth below. The DSRS is not a substitute for the NRC's regulations, and compliance with it is not required. As an alternative, and as described in more detail below, an applicant may identify the differences between a DSRS section and the design features (DC and COL applications only), analytical techniques, and procedural measures proposed in an application and discuss how the proposed alternative provides an acceptable method of complying with the NRC regulations that underlie the DSRS acceptance criteria.

1. GDC 5 is satisfied as it relates to sharing SSCs of the preferred power system. For NuScale, a multimodule plant, this review includes the entire switchyard and all circuitsfrom the switchyard to the onsite power distribution systems of each module.

2. GDC 17 is satisfied as it relates to the preferred power system's (1) capacity and capability to permit functioning of SSCs important to safety, (2) provisions to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from any onsite electric power supplies, (3) physical independence, (4) availability, and (5) capability to meet the guidelines of Appendix A to DSRS Section 8.2, regarding the acceptability of generator circuit breakers and generator load break switches applicable to the NuScale design.

3. GDC 18 is satisfied as it relates to the capability for inspection and testing of the offsite electric power system.

4. GDC 33, 34, 35, 38, 41, and 44 are satisfied as they relate to the operation of the offsite electric power system, encompassed in GDC 17, to ensure that the safety functions described in GDC 33, 34, 35, 38, 41, and 44 are accomplished, assuming a single failure where applicable.

5. 10 CFR 50.63 is satisfied if a passive design can cope with a station blackout (SBO) for 72 hours with no operator actions and using only the Class 1E direct current (dc) power system. The reviewer should verify this capability for the NuScale design. These issues are reviewed in detail in DSRS Section 8.4.

6. 10 CFR 50.65(a)(4), is satisfied as it relates to the requirements to assess and manage the increase in risk that may result from proposed maintenance activities before the maintenance activities are performed. Acceptance is based on meeting the following specific guidelines:

    A. RG 1.160, as it relates to the effectiveness of maintenance activities for onsite standby alternating current (ac) power sources, including grid-risk-sensitive maintenance activities (i.e., activities that tend to increase the likelihood of a plant trip, increase loss-of-offsite-power (LOOP) frequency, or reduce the capability to cope with a LOOP or SBO)

    B. Section 11 to NUMARC 93-01, Revision 4A, "Nuclear Energy Institute Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," April 2011

<u>Technical Rationale</u>

The technical rationale for the application of these acceptance criteria to the areas of review addressed by this DSRS section is discussed in the following paragraphs:

1. Compliance with GDC 5 requires that SSCs important to safety not be shared among nuclear power units, unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions.

    With regard to the NuScale design, this criterion requires that a shared switchyard in multimodule plant configurations meet GDC 5, thereby ensuring that an accident in one module of a multiple-module facility can be mitigated using an available complement of mitigative features, including required ac power, irrespective of conditions in the other units and without giving rise to conditions unduly adverse to safety in another unit.

In addition, meeting the requirements of GDC 5 provides assurance that an accident within any one unit of a multiple-module plant may be mitigated, irrespective of conditions in other units, without affecting the overall operability of the offsite power system.

2. Compliance with GDC 17 requires that onsite and offsite electrical power be provided to facilitate the functioning of SSCs important to safety. Each electric power system, assuming the other system is not functioning, must provide sufficient capacity and capability to ensure that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences (AOOs) and that the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

   GDC 17 further requires that electric power from the transmission network to the onsite electric distribution system be supplied by two physically independent circuits designed and located so as to minimize the likelihood of their simultaneous failure under operating, postulated accident, and postulated environmental conditions. Each of these circuits is required to be designed to be available in sufficient time following a loss of all onsite ac power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits is also required to be designed to be available within a few seconds following a loss-of-coolant accident (LOCA) to assure that core cooling, containment integrity, and other vital safety functions are maintained.

   Provisions should also be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power from the nuclear power unit, the transmission network, or the onsite electric power supplies. The trip of the nuclear power unit is an AOO that can result in reduced switchyard voltage; potentially actuating the plant's degraded voltage protection and separating the plant's safety buses from offsite power. It can also result in grid instability, potential grid collapse, inadequate switchyard voltages, and a subsequent LOOP due to loss of the real and/or reactive power support supplied to the grid from the nuclear unit. Plant TS limiting conditions for operation (LCOs) require the offsite power system to be operable. However, since the capability of the offsite power system cannot be tested except when challenged during an actual event, the design bases for the offsite power system can only be assured through analysis of the grid and plant conditions. Plant operators should therefore be aware of: (1) the capability of the offsite power system to supply power, as required by TS, during operation, and (2) situations that can result in a LOOP following a trip of the plant. Plant operators are expected to declare the offsite power system inoperable in the event of degraded grid conditions that cannot support adequate post-trip voltages. Additional information on the adequacy of grid voltage, grid stability, and grid-reliability challenges due to deregulation of the utility industry, and the effect of grid events on nuclear power plant (NPP) performance are provided in References 21, 24, 25, 29, 30, and 43.

GDC 17 also requires that onsite emergency power supplies (Class 1E batteries) and distribution systems have sufficient independence, redundancy, and testability to perform their safety functions, assuming a single failure. Therefore, no single failure will prevent the onsite emergency power system from supplying electric power, thereby permitting safety functions and other vital functions requiring electric power to be performed in the event of any single failure in the power system.

Passive reactor designs typically incorporate passive safety-related systems for core cooling and containment integrity, and therefore, do not depend on the electric power grid connection and grid stability for safe operation. However, passive reactor designs may also include active systems that can provide defense-in-depth capabilities for reactor coolant makeup and decay heat removal. The accident analysis and probabilistic risk analysis for NuScale should be reviewed to identify any such non-safety-related systems. If identified, review of the electrical design of the plant should confirm that any offsite power requirements for these systems are met. The AP1000 safety analyses, for example, assume that the reactor coolant pumps (RCPs) can receive power at 6.9 kV from either the main generator or the grid for a minimum of 3 seconds following a turbine trip, assuming no electrical fault. Should a turbine trip occur during power operation, the generator will continue rotating at synchronous speed by acting as a synchronous motor. Antimotoring protective relaying for the main generator will open the generator output breaker after a time delay of at least 15 seconds, during which time the rotating generator will provide voltage support for the grid. When the generator output breaker trips, the plant distribution system uses backfeed from the grid to maintain power to the RCPs. Therefore, grid stability analyses should verify that the grid remains stable for a minimum of 3 seconds following a turbine trip to support the assumptions made in the safety analyses for the passive reactor designs, such as the AP1000. The reviewer should verify if any similar constraints are placed on the NuScale design.

In response to the Byron NPP event that rendered the offsite power circuits inoperable when a loss of single-phase open-circuit condition was not detected promptly, the staff issued NRC Bulletin 2012-01 to all operating/licensed reactors and analogous requests for additional information (RAIs) to COL applicants to address this design vulnerability by requesting information on their offsite power circuit protection scheme with regard to GDC 17 compliance. Based upon the responses to the Bulletin and RAIs, and working in conjunction with the Nuclear Energy Institute, the staff developed a set of acceptance criteria documented in SRP BTP 8-9 “Open Phase Conditions in Electric Power System.” Section B.3 specifically addresses passive reactor designs.

Passive reactor designs should provide automatic detection of an offsite power system open-circuit condition (1 or 2 phases) with or without a high impedance ground-fault condition on the high-voltage side of the main power transformer under all loading and operating configurations. In addition, an alarm should be provided in the main control room so that operators may take manual action, if the standby ac power supplies or a remaining offsite power line is not automatically connected to the plant buses. This ensures that ac power, with adequate capacity and capability, is available to the equipment important to safety, including safety-related battery chargers, to meet their intended safety function in accordance with GDC 17 requirements. To complement the physical design, ITAAC should be established to provide analyses for relay set points and testing to demonstrate functionality. Also, a full complement of procedures and attendant training should be established to cover operator response, maintenance, and testing. Institute of Electrical and Electronics Engineers (IEEE) Standard (Std.) 308, as modified/supplemented by the regulatory positions of RG 1.32, establishes additional guidance for meeting the requirements of GDC 17.

Meeting the requirements of GDC 17 provides assurance that a reliable electric power supply (i.e., onsite and offsite power together) can be provided for all facility operating modes, including AOOs and design-basis accidents to permit safety functions and other vital functions to be performed, even in the event of a single failure.

3. Compliance with GDC 18 requires that the offsite, preferred electric power system be designed to permit appropriate periodic inspection and testing of key areas and features to assess their continuity and the condition of their components. This system shall be designed to test periodically: (1) the operability and functional performance of the components of the offsite power system, such as relays, switches, circuit breakers, and buses, and (2) the operability of the systems as a whole and, under conditions as close to design as practicable, the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

   This criterion requires that the ac power system provide the capability to perform integral testing on a periodic basis.

   Meeting the requirements of GDC 18 provides assurance that, when required, the offsite power system can be appropriately and unobtrusively accessed for required periodic inspection and testing, enabling verification of important system parameters, performance characteristics, and features, and the detection of degradation or impending failure under controlled conditions.

4. GDC 33, 34, 35, 38, 41, and 44 set forth requirements for the safety systems for which the access to both offsite and onsite electric power sources must be provided. Compliance with these criteria requires that capability be provided for reactor coolant makeup during small breaks (GDC 33), residual heat removal (GDC 34), emergency core cooling (GDC 35), containment heat removal (GDC 38), containment atmosphere cleanup (GDC 41), and cooling water for SSCs important to safety (GDC 44). These systems must be available during normal and accident conditions, as required by each specific GDC.

   For the AP1000 passive reactor design, the potential risk contribution of each design-basis event (DBE) was determined to be minimized by not requiring ac power sources for any DBEs. Such passive reactor designs incorporate passive safety-related systems for core cooling and containment integrity and, therefore, do not depend on the electric power grid connection and grid stability for safe operation. They are designed to automatically establish and maintain safe-shutdown conditions after DBEs for the first 72 hours, without operator action, following a loss of both onsite and offsite ac power sources. Consequently, such passive reactor designs are not required to meet the requirements of GDC 33, 34, 35, 38, 41, and 44 for 72 hours. The reviewer should verify that these design parameters and specific systems hold true for the NuScale design when this review begins. If not, and to that extent, no further review of this topic is necessary.

5 Compliance with 10 CFR 50.63 requires that each light-water-cooled NPP be able to withstand or cope with, and recover from, an SBO.

For the AP1000 passive reactor design, the potential risk contribution of an SBO was determined to be minimized by not requiring ac power sources for DBEs. The safety-related passive systems in these plants do not need non-safety-related ac power sources to perform safety-related functions. They are designed to automatically establish and maintain safe-shutdown conditions after DBEs for the first 72 hours, without operator action, following a loss of both onsite and offsite ac power sources. Consequently, such passive reactor designs have been determined to meet the requirements of 10 CFR 50.63 for 72 hours. The reviewer should verify that these design parameters hold for the NuScale design.

Meeting the requirements of 10 CFR 50.63 provides assurance that the nuclear power plant will be able to withstand or cope with, and recover from, an SBO and will ensure that core cooling and appropriate containment integrity are maintained.

5. 10 CFR 50.65 (a)(4) requires that licensees assess and manage the increase in risk that may result from the proposed maintenance activities before such activities are performed. Grid stability and offsite power availability are examples of emergent conditions that may result in the need for action before conducting the assessment or that could change the conditions of a previously performed assessment. Accordingly, licensees should perform grid-reliability evaluations as part of the maintenance risk assessment before performing “grid-risk-sensitive” maintenance activities (such as surveillances, postmaintenance testing, and preventive and corrective maintenance). Such activities are those that could increase risk under existing or imminent degraded grid-reliability conditions, including (1) conditions that could increase the likelihood of a plant trip, (2) conditions that could increase the likelihood of a LOOP or SBO, and (3) conditions that could have an impact on the plant’s ability to cope with a LOOP or SBO, such as out-of-service, risk-significant equipment (for example: a Class 1E battery, a steam-driven pump, or any alternately available ac power source).

III. REVIEW PROCEDURES

These review procedures are based on the identified DSRS acceptance criteria. For deviations from these acceptance criteria, the staff should review the applicant’s evaluation of how the proposed alternatives provide an acceptable method of complying with the relevant NRC requirements identified in Subsection II.

1. Selected Programs and Guidance—In accordance with the guidance in NUREG–0800, “Introduction – Part 2: Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: Light-Water Small Modular Reactor Edition” (NUREG-0800, Intro Part 2), as applied to this DSRS Section, the staff will review the information proposed by the applicant to evaluate whether it meets the acceptance criteria described in Subsection II of this DSRS. As noted in NUREG-0800, Intro Part 2, the NRC requirements that must be met by an SSC do not change under the small modular reactor (SMR)

framework. Using the graded approach described in NUREG-0800, Intro Part 2, the NRC staff may determine that, for certain SSCs, the applicant's basis for compliance with other selected NRC requirements may help demonstrate satisfaction of the applicable acceptance criteria for that SSC in lieu of detailed independent analyses. The design-basis capabilities of specific SSCs would be verified, where applicable, as part of completing the applicable ITAAC. The use of the selected programs to augment or replace traditional review procedures is shown in Figure 1 of NUREG-0800, Intro Part 2. Examples of such programs that may be relevant to the graded approach for these SSCs include:

- 10 CFR Part 50, Appendix A, GDC, Overall Requirements, Criteria 1–5
- 10 CFR Part 50, Appendix B, Quality Assurance (QA) Program
- 10 CFR 50.49, Environmental Qualification of Electrical Equipment (EQ) Program
- 10 CFR 50.55a, Code Design, Inservice Inspection, and Inservice Testing (ISI/IST) Programs
- 10 CFR 50.65, Maintenance Rule requirements
- Reliability Assurance Program (RAP)
- 10 CFR 50.36, "Technical Specifications"
- Availability Controls for SSCs Subject to Regulatory Treatment of Nonsafety Systems (RTNSS)
- Initial Test Program (ITP)
- Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC)

This list of examples is not intended to be all inclusive. It is the responsibility of the technical reviewers to determine whether the information in the application, including the degree to which the applicant seeks to rely on such selected programs and guidance, demonstrates that all acceptance criteria have been met to support the safety finding for a particular SSC.

2. In accordance with 10 CFR 52.47(a)(8), (21), and (22), and 10 CFR 52.79(a)(17), (20), and (37), for DC or COL applications submitted under 10 CFR Part 52, the applicant is required to (1) address the proposed technical resolution of unresolved safety issues and medium- and high-priority generic safety issues which are identified in the version of NUREG-0933, "Resolution of Generic Safety Issues," current on the date up to 6 months before the docket date of the application and which are technically relevant to the design, (2) demonstrate how the operating experience insights have been incorporated into the plant design, and (3) provide information necessary to demonstrate compliance with any technically relevant portions of the Three Mile Island requirements set forth in 10 CFR 50.34(f), except paragraphs (f)(1)(xii), (f)(2)(ix), and (f)(3)(v), for a DC application, and except paragraphs (f)(1)(xii), (f)(2)(ix), (f)(2)(xxv), and (f)(3)(v),for a COL application.

These cross-cutting review areas should be addressed by the reviewer for each technical subsection and relevant conclusions documented in the corresponding safety evaluation report (SER) section.

3. To verify that the requirements of GDC 17 are satisfied, the following review steps should be taken:

   A. The electrical drawings should be examined to ensure that at least two separate circuits from the transmission network to the onsite power distribution system buses are provided (a single switchyard may be common to these paths).For the AP1000 passive reactor design, the passive safety-related systems require electric power for valves and related instrumentation, which can be supplied from the onsite Class 1E batteries and associated dc and vital ac distribution systems. If no offsite power is available, it is expected that the -RTNSS standby diesel generators would be available for important plant functions. However, this non-safety-related ac power is not relied on to maintain core cooling or containment integrity.

      As documented in SECY 94-084 and SECY-95-132, the staff addressed technical issues associated with the RTNSS process in passive plant designs. Non-safety-related, risk-significant active systems in passive light-water reactors may have a significant role in accident and consequence mitigation by providing defense-in-depth functions to supplement the capability of the safety-related passive systems. For example, in the AP1000 passive reactor design, ac power from an offsite system is required to power the normal residual heat removal system (RHR) and also to provide a means of supplying power to postaccident monitoring and ac input power for Class 1E dc battery chargers. The RHR system provides a non-safety-related means available to inject water into the reactor coolant system for reactor coolant makeup and decay heat removal. The NuScale design review should therefore identify any offsite power requirements to support non-safety-related, risk-significant active systems identified through the RTNSS process.

   B. The routing of transmission lines should be examined on the station layout drawings and verified during the site visit to ensure that at least two circuits from the offsite grid to the onsite distribution buses are physically separate and independent. No other lines should cross above these two circuits. Attention should be directed toward ensuring that no single event, such as a tower falling or a line breaking, can simultaneously affect both circuits in such a way that neither can be returned to service in time to prevent fuel design limits or design conditions of the reactor coolant pressure boundary from being exceeded. In addition, the reviewer should verify that no single-point vulnerability exists whereby a weather-related event could disable any portion of the preferred power sources and simultaneously cause failure of the onsite power sources.

   C. As the switchyard may be common to multiple offsite circuits, the electrical schematics of the switchyard breaker control system, its power supply, and the breaker arrangement itself should be examined for the possibility of simultaneous failure of multiple circuits from single events, such as a breaker not operating during fault conditions, spurious relay trip, loss of a control circuit power supply, or a fault in a switchyard bus or transformer. Reference 27 describes an example of a single-failure susceptibility of a transmission line protection scheme that was the primary cause of a cascading blackout and LOOP event In addition, the reviewer should examine the failure modes and effects analysis of the switchyard by the applicant to verify that no single event would simultaneously fail multiple offsite power circuits.

D. The design is examined to determine that at least one required circuit can, within a few seconds, provide power to safety-related equipment following a LOCA. GDC 17 does not require each circuit provided in itself to be single-failure-proof for this accident. However, it is required that each circuit have the capability to be available in sufficient time to prevent fuel design limits and design conditions of the reactor coolant pressure boundary from being exceeded. Therefore, the design is examined to determine that, assuming no offsite ac power is available, the period of time that the station can remain in a safe condition (onsite power is assumed to be available) is greater than the time required to reestablish ac power from the offsite grid to the onsite Class 1E distribution buses for each single failure event.

The switchyard circuit breaker control scheme should be such that any incoming transmission line, switchyard bus, or path to the onsite safety-related distribution buses can be isolated, so that ac power can be reestablished to the onsite Class 1E buses through its redundant counterpart (as may be available in the NuScale DC/COL design). This should be achieved with separate and redundant breaker tripping and closing devices that are actuated by redundant dc battery supplies. Operating experience events (Reference 27) can provide further information for the reviewer on the importance of redundancy in transmission grid protective schemes.

For those designs that take credit for a backfeed path through the main generator step-up transformer, the reviewer should first ascertain if this path is required to satisfy the GDC 17 requirement for an immediate or delayed access circuit. If the circuit is for delayed access only, then the same determination (as discussed in the previous paragraph) should be made (i.e., there is sufficient time to make this circuit available (assuming the availability of the grid itself but the unavailability of the immediate access circuit and the onsite power supplies) such that the reactor remains in a safe condition). If the circuit is required for immediate access or uses generator circuit breakers or generator load break switches, then the reviewer should use the guidelines contained in Appendix A to this DSRS section. [Note: the term “generator circuit breaker” used in this context refers to a circuit breaker between the main generator and the main step-up transformer—generally in the 25-kV rating range.]

E. Each of the circuits from the offsite system to the onsite distribution buses shall have the capacity and capability to supply the loads assigned to the bus or buses it is connected to during normal or abnormal operating, accident, or plant shutdown conditions. Therefore, the loads to be supplied during these conditions should be determined from information obtained in coordination with other staff. The capacity and electrical characteristics of transformers, circuit breakers, buses, transmission lines, other electrical equipment, and the preferred power source for each path should be evaluated to ensure that there is adequate capability to supply the maximum connected load during all plant conditions. The design should also be examined to ensure that, during transfer from one power source to another, the design limits of equipment are not exceeded. Industry standards (References 46 and 48) and, for COL applications, RG 1.206 (Section C.I.8.2.2), provide further information for the reviewer regarding power system analytical studies to verify the capability of the offsite power systems and their interfaces with the onsite power system.

F. The results of the grid stability analysis should show that loss of the largest single supply to the grid does not result in the complete loss of preferred power. The analysis should consider the loss, through a single event, of the largest capacity being supplied to the grid, removal of the largest load from the grid, or loss of the most critical transmission line. This could be the total output of the station, the largest station on the grid, or possibly several large stations, if these use a common transmission tower, transformer, or breaker in a remote switchyard or substation. The station layout and the grid system layout drawings are reviewed to determine that all the above events were included in the analysis. SRP BTP 8-6, industry standards (e.g., References 46 and 48) and, for COL applications, RG 1.206 (Section C.I.8.2.2), provide further information for the reviewer regarding stability studies of offsite power systems.

The reviewer verifies that the grid stability analysis considers the effect of grid events on the adequacy of offsite grid voltage available at the plant switchyard. Operating experience has shown that a variety of factors, such as power flow through the transmission grid, reactive power capacity, the plant voltage and frequency protective schemes and setpoints, and weather or temperature conditions in the region can all affect grid voltage levels and overall stability. DSRS BTP 8-6 and References 21, 25, 29, 30, and 43 provide information for the reviewer regarding degraded transmission grid voltage and the effects of grid events on grid voltage at the plant switchyard. The applicant should include in the grid stability analysis the consideration of failure modes that could result in ac frequency variations exceeding the maximum rate of change determined in the accident analysis for loss-of-reactor-coolant flow. Failure modes that could produce abnormal frequency events and the plant frequency protection schemes are reviewed. Abnormal frequency operating experience from the assessment of grid transient events (Reference 43) and industry standards (Reference 54) provide further information on abnormal frequency considerations at nuclear power plants.

Passive reactor designs typically incorporate passive safety-related systems for core cooling and containment integrity and, therefore, do not depend on the electric power grid connection and grid stability for safe operation. Passive reactor designs may also include active systems that can provide defense-in-depth capabilities for reactor coolant makeup and decay heat removal. The accident analysis and probabilistic risk analysis for the NuScale design should be reviewed to identify any nonsafety-related systems that are relied upon to provide risk-significant functions. Once identified, review of the electrical design of the plant should confirm that any offsite power requirements for these systems are met.

G. During the review of the electrical schematics, it should be determined that (1) loss of any standby power will not result in loss of preferred power, (2) loss of one preferred power circuit will not result in loss of any other circuit, (3) loss of the main generator will not result in loss of any preferred power circuit, and (4) loss of any combination of these power sources will not prevent the use of the Class 1E dc power system.

H. The reviewer verifies that the preferred power system is independent of the onsite power system. The basis for acceptance is that no single event, including a single protective relay, interlock, or switchgear failure, in the event of loss of all standby power sources, will prevent the separation of the preferred power system from the onsite power distribution system or prevent the preferred power system from accomplishing its intended functions. In addition, the preferred and standby power supplies should not have common failure modes. An acceptable design should be capable of restoring the preferred power supply after the loss of either circuit in a time period such that the plant can be safely shut down, taking into account the effects of a single failure in the onsite distribution system. This item is also addressed in DSRS Section 8.3.1.

I. The reviewer verifies that adequate provisions are made in the design of the plant and the offsite and onsite power systems for grounding, surge protection, and lightning protection. The reviewer evaluates the plant/station grounding systems, the methods of equipment and structural grounding, ac power system neutral grounding and ground fault current limiting features, surge and lightning protection features for outdoor equipment and circuits, and the measures for isolating instrumentation grounding systems. RG 1.204 and IEEE Stds. 665, 666, 1050, and C62.23, provide acceptable guidelines for the design, installation, and performance of station grounding systems and surge and lightning protection systems.

J. The reviewer should verify that provisions are included in the design to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies. The trip of the nuclear power unit is an AOO that can result in reduced switchyard voltage, potentially actuating the plant's degraded voltage protection and separating the plant's safety buses from offsite power. It can also result in grid instability, potential grid collapse, inadequate switchyard voltages, and a subsequent LOOP due to loss of the real or reactive power support supplied to the grid from the nuclear unit. Plant TS LCOs require the offsite power system to be operable. However, since the capability of the offsite power system cannot be tested except when challenged during an actual event, the design bases for the offsite power system can only be assured through analysis of the grid and plant conditions. Plant operators should, therefore, be aware of: (1) the capability of the offsite power system to supply power, as required by TS, during operation, and (2) situations that can result in a LOOP following a trip of the plant. Plant operators are expected to declare the offsite power system inoperable in the event of degraded grid conditions that cannot support post-trip voltages. Further, the reviewer should verify that communications (both voice and data) between the NPP and its offsite transmission system operating authorities are implemented in assessing whether the offsite power sources are operable, as required by GDC 17 and the plant TS. In addition, the reviewer should verify that grid-reliability evaluations, performed as part of the maintenance risk assessment required by 10 CFR 50.65 before conducting "grid-risk-sensitive" maintenance activities, are considered when evaluating the operability of the offsite power system.

The applicant's methods and procedures for confirming the operational readiness of offsite power systems are reviewed to verify that plant operators are aware of the capability of the offsite power system to supply power during operation and situations that can result in a LOOP following a trip of the plant. This includes a review of communication agreements and protocols that exist between the NPP and the transmission system operator (TSO), independent system operator (ISO), or reliability coordinator/authority. The agreements and protocols should be verified to include preferred operating limits for the offsite power system and preferred actions for recovering from a LOOP event. It should also include the use of transmission load flow analysis and real time contingency analysis software tools (analysis tools) (directly or through the TSO) to assist the NPP in monitoring grid conditions and operating status to determine the operability of offsite power systems under plant TS. The review should verify that the communication protocols are enforced by a formal contract or other means and include notification requirements to inform the NPP when the grid is stressed to the point where a trip of the NPP would result in inadequate post-trip switchyard voltages (less than the design-basis voltage) for either actual grid conditions or potential (i.e., anticipatory contingency) grid conditions within any predetermined time limits. Additionally, the reviewer may perform independent calculations using the electronic copy of the model of the onsite distribution system provided by the applicant to ensure that each offsite power circuit has sufficient capacity and capability to provide power to the safety loads. See Section 8.3 for details. The reviewer should also review the description of the analysis tool used by the TSO to determine, in real time, the impact that the loss or unavailability of various transmission system elements will have on the condition of the transmission system to ensure that adequate post-trip voltages are available at the switchyard.

The true capability of the offsite source cannot necessarily be verified through direct readings of plant switchyard or safety bus voltages. Recent operating experience (Reference 43) has shown that analyses of the surrounding grid and plant conditions, based on accurate and timely transmission system data, are needed to evaluate all possible contingencies at a given time. The reviewer should verify that adequate status information, communications, analytical resources, and procedures are provided to determine that the plant is operating within the offsite power grid operability limits required by GDC 17 and the plant's TS. The information and guidance provided in NRC generic communications

(Reference 21), industry standards (Reference 50), and other NRC documents (e.g., References 22, 24, 25, 29, 30, and 43) are useful in reviewing the adequacy and reliability of the plant's interface with the offsite power grid and communicating with offsite transmission system operating authorities.

K. The reviewer should verify that adequate procedures, administrative controls, and protocols are in place to ensure that no modifications to the offsite power system circuits credited for satisfying GDC 17 are implemented by offsite transmission system operating authorities, responsible for maintenance, modification, and operation of the offsite transmission grid, without the performance of a proper safety evaluation. The safety evaluation of transmission system modifications is required to ensure that the transmission grid configuration, stability, and capability remain within the assumptions of the plant safety analyses. Further information on potential unreviewed safety questions associated with modifications to offsite transmission circuits can be found in Reference 45. In addition, the reviewer should verify that grid-reliability evaluations are performed for maintenance or modifications to the offsite power system, as part of the maintenance risk assessment required by 10 CFR 50.65 before "grid-risk-sensitive" maintenance activities are performed.

L. Operating experience has shown that undetected degradation of underground electric cables due to protracted exposure to wetted environments or submergence in water or resulting from preexisting manufacturing defects could result in multiple equipment failures. Underground or inaccessible power and control cable runs that are susceptible to protracted exposure to wetted environments or submergence as a result of water intrusion from tidal, seasonal, or weather events are reviewed. Cables from independent power sources or different safety divisions could be affected by the same condition. Underground or inaccessible power cables connecting offsite power to safety buses or power and control cables to equipment with accident mitigating functions should be considered in the review. Examples from operating experience of submerged cable failures are provided in Reference 26.

4. To ensure that the requirements of GDC 18 are satisfied, the detailed description of the design should be examined to determine that the design includes provisions for testing the transfer of the source of power feeding the onsite distribution system (e.g., from the main generator supply to the preferred power system, or to any other supply). It should also be established that the circuitry required to perform these transfer functions has the capability of being tested during plant operation. The organization responsible for QA and maintenance should review preoperational and initial startup test procedures. The organization responsible for QA and maintenance should also review the periodic test procedures.

   RG 1.204 provides acceptable guidelines for an adequate and acceptable testing and maintenance approach for the reviewer to confirm the proper installation of a lightning protection system (LPS) and ensure its continued ability to provide the level of protection for which it was designed. The reviewer should verify that new LPSs are inspected following installation and reinspected at least on a regular, periodic basis throughout their lifetime. In particular, an LPS should be inspected whenever any alterations or repairs are made to a protected structure, as well as following any known lightning transient to the system. An LPS should be visually inspected at least annually. In areas where severe climatic changes occur, it is advisable to inspect the LPS semiannually or following extreme changes in ambient temperature. The reviewer should verify that testing and maintenance procedures are established for each LPS. The frequency of testing and maintenance will depend on the weather-related degradation of protective features, the frequency and severity of damage attributable to lightning transients, and the required protection level. The LPS testing and maintenance program is reviewed for the following activities: (1) inspection of all conductors and system components, (2) tightening of all clamps and splices, (3) measurement of the earth grounding resistance, (4) measurement of the resistance of ground terminals, (5) inspection or testing (or both) of surge protection devices to assess their effectiveness, (6) periodic testing and maintenance of earth grounding systems, (7) refastening and tightening of components and conductors as required, (8) inspection and testing when the LPS has been altered by additions to, or changes in, the structure, and (9) complete records.

5. GDC 33, 34, 35, 38, 41, and 44 set forth requirements for the safety systems with a source of power that include the preferred power system. These criteria state that safety system redundancy shall be such that, for preferred power system operation (assuming standby power is not available), the system safety function can be accomplished assuming a single failure. Note: the single failure criterion as applicable to these GDC does not apply to the preferred power system. As noted previously in Section II, the reviewer should verify whether or not the power system requirements associated with these GDC apply to the NuScale design.

6. All offsite power system equipment and components in the station switchyard and its connection to the onsite Class 1E system are reviewed to determine that they are appropriately included in a QA program. Safety-related equipment and components, and those required to support systems with accident mitigating functions, should have the appropriate quality classifications. The review should verify that procedures, maintenance, and surveillance tests associated with the equipment and components incorporate the appropriate quality controls. The organization responsible for QA and maintenance should determine the adequacy of the QA program.

7. To verify that the offsite power system is designed to operate in its environment, the organization responsible for civil engineering and geosciences review should provide to the organization responsible for electrical engineering review, upon request, information on the design basis, high and low atmospheric temperatures, high wind, rain, lightning discharges, ice and snow conditions, and weather events causing regional effects. This information should be considered during the review to verify that the design minimizes the effects of these conditions in accordance with GDC 17. Items such as switchyard and transformer locations, transformer cooling, overhead transmission lines, and underground or inaccessible power and control cables could be affected by these conditions. Operating experience provides additional information on the effects of severe heat and cold on electrical system equipment (References 23 and 28) and on the effects of protracted submergence and wet environments on underground electric cables (Reference 26).

   Communication links between the plant operators and local TSO/ISOs serve as a means to obtain timely information on power grid operating conditions and status to verify the operability of the offsite power grid, in accordance with the requirements of the plant's TS. Communications with offsite entities are also important for restoration of offsite power in the event of a LOOP or SBO. The plant's offsite communications equipment and protocols, communication contingency procedures, communications circuit routing, and telemetry links used to monitor the power grid and to verify and maintain grid stability and operability should be reviewed to determine that they are secure and will continue to function during severe weather events causing regional effects. Operating experience provides additional information on offsite communications capability and integrity during severe weather events (Reference 22).

8. To ensure that the design of the offsite power system (i.e., the switchyard and all circuits to the onsite distribution systems at the facility) is protected from potential dynamic effects, the organization responsible for the review of plant systems, upon request, should review the location of SSCs of the preferred power system to identify any related threats. If any threats are identified, that reviewer should determine if the protection provided against dynamic effects (including effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures and from events and conditions outside the station) is acceptable. This information should be used to determine the possibility of simultaneous loss of multiple paths of preferred power.

9. The NuScale design does not share any safety-significant SSCs between multiple reactor modules. The exception to this is that the modules do share a common switchyard. Therefore, to ensure that the requirements of GDC 5 are satisfied, the SSCs of the preferred power system (i.e., the switchyard and all circuits connecting to the reactor modules) should be reviewed to ascertain that they have sufficient capacity and capability to perform all required safety functions in the event of an accident in one unit, with a simultaneous orderly shutdown and cooldown of the remaining units. Review of the design criteria should establish that the capacity and capability of incoming lines, power sources, and transformers for each required circuit have enough margin to achieve this. Spurious or false accident signals should not overload these circuits. DSRS Section 8.3.1 further discusses spurious or false accident signal considerations.

10. The preferred power system instrumentation provided to monitor variables and equipment status should be identified during the electrical schematic and system description review. It should be ascertained that these instruments present status information that can be used to determine the condition of the preferred power system at all times. Review of the electrical schematics should determine that controls (automatic, manual, or remote) are provided to maintain these variables and systems within prescribed operating ranges. It should also be determined, during the review of the electrical schematics, the effects that failures of these controls and instruments might have on the preferred power system.

11. The review of any automatic TSO action should ascertain that TSO actions (including normal and postulated failure modes of operation) will not interfere with safety actions that may be required of the reactor protection system. This system should also be reviewed to ensure that no failure mode of the TSO system will cause an incident at the generating station that would require protective action.

12. The Maintenance Rule, Section 50.65(a)(4), requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before the maintenance activities are performed. RG 1.160 provides guidance for assessing and managing the increase in risk that may result from maintenance activities and for implementing the optional reduction in scope of SSCs considered in the assessment. The review should verify that grid reliability evaluations are performed, as part of the maintenance risk assessment required by 10 CFR 50.65, before the performance of "grid-risk-sensitive" maintenance activities, including, but not limited to, surveillances, postmaintenance testing, and corrective and preventive maintenance. Activities that could increase risk under existing or imminent degraded grid reliability conditions include: (1) conditions that could increase the likelihood of a plant trip, (2) conditions that could increase the likelihood of a LOOP or SBO, and (3) conditions that have an impact on the plant's ability to cope with a LOOP or SBO, such as out-of-service risk-significant equipment.

    For reviews of DC and COL applications under 10 CFR Part 52, the reviewer should follow the above procedures to verify that the design set forth in the Chapter 15 safety analyses, and, if applicable, site interface requirements meet the acceptance criteria. For DC applications, the reviewer should identify necessary COL action items. In general, for the review of a COL application, the scope of the review is dependent on whether the COL applicant references a DC, an early site permit (ESP), or other NRC approvals (e.g., site suitability report or topical report). However, the scope of this DSRS section specifically addresses the NuScale DC. After this review, SRP Sections 14.3 and 14.3.6 should be followed for the review of Tier I information for the design, including the postulated site parameters, interface criteria, and ITAAC.

IV. EVALUATION FINDINGS

The offsite power system includes two or more identified transmission lines from the grid to the plant switchyard and two or more circuits from the switchyard to each reactor unit's onsite distribution system. The review of the offsite power system for a NuScale COL application covered single-line diagrams, station layout drawings, and descriptive information.

The basis for acceptance of the offsite power system in our review was conformance of the design criteria and bases to the Commission's regulations as set forth in the GDC of Appendix A to 10 CFR Part 50. The staff concludes that the plant design is acceptable and meets the requirements of GDC 5, 17, and 18. This conclusion is based on the following:

1. The applicant has met the requirements of GDC 5 with respect to sharing circuits of the preferred power system, including the common switchyard and all circuits from the switchyard to the various reactor units. Each circuit has sufficient capacity to operate the engineered safety features for a design-basis accident on one unit and those systems required for concurrent safe-shutdown on the remaining units.

2. The applicant has met the requirements of GDC 17 with respect to the offsite power system's (1) capacity and capability to permit functioning of SSCs important to safety, (2) provisions to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the

nuclear power unit or loss of power from the onsite electric power supplies, (3) physical independence of circuits, and (4) availability of circuits. The preferred power system consists of at least two physically independent circuits routed from the electrical grid system by transmission lines to the facility switchyard and then two circuits to the onsite power distribution system. At least one circuit will be available within a few seconds following a LOCA and is considered an immediate access circuit. All circuits provided are designed and located so as to minimize, to the extent practicable, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. Each circuit has been sized with sufficient capacity to supply all connected loads. Each circuit can be made available to the onsite power system, assuming loss of the onsite dc power supplies to ensure that fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. The switchyard is arranged such that each offsite circuit can be isolated from other circuits to permit the reestablishment of offsite power to the onsite distribution system. The switchyard is also arranged such that single events (e.g., a spurious relay trip or a breaker not operating during fault conditions) will not cause simultaneous failure of all provided offsite circuits to the switchyard. The results of the applicant's grid stability analysis indicated that loss of the largest generating capacity being supplied to the grid, loss of the largest load from the grid, loss of the most critical transmission line, or loss of the unit itself will not cause grid instability.

3. The applicant has met the requirements of GDC 18 with respect to the capability to test systems and associated components during normal plant operations and the capability to test the transfer of power from the nuclear power unit, the offsite preferred power system, and the onsite power system.

For DC and COL reviews, the findings will also summarize the staff's evaluation of requirements and restrictions (e.g., interface requirements and site parameters) and COL action items relevant to this DSRS section.

In addition, to the extent that the review is not discussed in other SER sections, the findings will summarize the staff's evaluation of the ITAAC, including design acceptance criteria, as applicable.

V. IMPLEMENTATION

The regulations in 10 CFR 52.17(a)(1)(xii), 10 CFR 52.47(a)(9), and 10 CFR 52.79(a)(41) establish requirements for applications for ESPs, DCs, and COLs, respectively. These regulations require the application to include an evaluation of the site (ESP), standard plant design (DC), or facility (COL) against the SRP revision in effect 6 months before the docket date of the application. While the SRP provides generic guidance, the staff developed the SRP guidance based on the staff's experience in reviewing applications for construction permits and operating licenses for large light-water nuclear power reactors. The proposed SMR designs, however, differ significantly from large light-water nuclear power plant designs.

In view of the differences between the designs of SMRs and the designs of large light-water power reactors, the Commission issued Staff Requirements Memorandum (SRM)-COMGBJ-10-0004/COMGEA-10-0001, "Use of Risk Insights To Enhance Safety Focus of Small Modular Reactor Reviews," dated August 31, 2010. In the SRM, the Commission directed the staff to develop risk-informed licensing review plans for each of the SMR design reviews, including plans for the associated preapplication activities. Accordingly, the staff has developed the content of the DSRS as an alternative method for evaluating a NuScale-specific application submitted pursuant to 10 CFR Part 52, and the staff has determined that each application may address the DSRS in lieu of addressing the SRP, with specified exceptions. These exceptions include particular review areas in which the DSRS directs reviewers to consult the SRP and others in which the SRP is used for the review. If an applicant chooses to address the DSRS, the application should identify and describe all differences between the design features (DC and COL applications only), analytical techniques, and procedural measures proposed in an application and the guidance of the applicable DSRS section (or SRP section, as specified in the DSRS), and discuss how the proposed alternative provides an acceptable method of complying with the regulations that underlie the DSRS acceptance criteria.

The staff has accepted the content of the DSRS as an alternative method for evaluating whether an application complies with NRC regulations for NuScale SMR applications, provided that the application does not deviate significantly from the design and siting assumptions made by the NRC staff while preparing the DSRS. If the design or siting assumptions in a NuScale application deviate significantly from the design and siting assumptions the staff used in preparing the DSRS, the staff will use the more general guidance in the SRP, as specified in 10 CFR 52.17(a)(1)(xii), 10 CFR 52.47(a)(9), or 10 CFR 52.79(a)(41), depending on the type of application. Alternatively, the staff may supplement the DSRS section by adding appropriate criteria to address new design or siting assumptions.

VI. REFERENCES

1. 10 CFR 50.2, "Definitions."

2. 10 CFR 50.63, "Loss of All Alternating Current Power."

3. 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants."

4. Intentionally left blank

5. Intentionally left blank

6. 10 CFR Part 50, Appendix A, GDC 5, "Sharing of Structures, Systems, and Components."

7. 10 CFR Part 50, Appendix A, GDC 17, "Electric Power Systems."

8. 10 CFR Part 50, Appendix A, GDC 18, "Inspection and Testing of Electric Power Systems."

9. 10 CFR Part 50, Appendix A, GDC 33, "Reactor Coolant Makeup."

10. 10 CFR Part 50, Appendix A, GDC 34, "Residual Heat Removal."

11. 10 CFR Part 50, Appendix A, GDC 35, "Emergency Core Cooling."

12. 10 CFR Part 50, Appendix A, GDC 38, "Containment Heat Removal."

13. 10 CFR Part 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup."

14. 10 CFR Part 50, Appendix A, GDC 44, "Cooling Water."

15. SRP BTP 8-6, "Adequacy of Station Electric Distribution System Voltages."

16. SRP BTP 8-3, "Stability of Offsite Power Systems."

17. DSRS Section 8.1, Table 8-1, "Acceptance Criteria for Electric Power.'

18. SRP BTP 8-9, "Open Phase Conditions in Electric Power System."

19. Appendix A to DSRS Section 8.2, "Guidelines for Generator Circuit Breakers/Load Break Switches."

20. SRM-COMGBJ-10-0004/COMGEA-10-0001, "Use of Risk Insights To Enhance Safety Focus of Small Modular Reactor Reviews," dated August 31, 2010

21. NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," February 1, 2006.

22. NRC Information Notice 97-05, "Offsite Notification Capabilities," February 27, 1997.

23. NRC Information Notice 98-02, "Nuclear Power Plant Cold Weather Problems and Protective Measures," January 21, 1998.

24. NRC Information Notice 98-07, "Offsite Power Reliability Challenges from Industry Deregulation," February 27, 1998.

25. NRC Information Notice 2000-06, "Offsite Power Voltage Inadequacies," March 27, 2000.

26. NRC Information Notice 2002-12, "Submerged Safety-Related Electrical Cables," March 21, 2002.

27. NRC Information Notice 2005-15, "Three-Unit Trip and Loss of Offsite Power at Palo Verde Nuclear Generating Station," June 1, 2005.

28. NRC Information Notice 2006-06, "Loss of Offsite Power and Station Blackout Are More Probable During Summer Period," March 3, 2006.

29. NRC Regulatory Issue Summary 2000-24, "Concerns About Offsite Power Voltage Inadequacies and Grid Reliability Challenges Due to Industry Deregulation," December 21, 2000.

30. NRC Regulatory Issue Summary 2004-05, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," April 15, 2004.

31. SECY-90-16, “Evolutionary Light Water Reactor Certification Issues and Their Relationships to Current Regulatory Requirements,” January 12, 1990. Approved in the SRM of June 26, 1990.

32. SECY-91-078, “EPRI’s Requirements Document and Additional Evolutionary LWR Certification Issues,” 1991. Approved in the SRM of August 15, 1991.

33. SECY-94-084, “Policy and Technical Issues Associated with the Regulatory Treatment of Non-safety Systems in Passive Plant Designs,” dated March 28, 1994. Approved in the SRM of June 30, 1994.

34. SECY-95-132, “Policy and Technical Issues Associated with the Regulatory Treatment of Non-safety Systems (RTNSS) in Passive Plant Designs.” Approved in the SRM of June 28, 1995.

35. NRC Memorandum; From: D. Crutchfield; To: File; Subject: Consolidation of SECY-94-084 and SECY-95-132, July 24, 1995.

36. SECY-94-084 was approved in the SRM of June 30, 1994. SECY-95-132 was approved in the SRM of June 28, 1995.

37. SECY-05-0227, “Final Rule B AP1000 Design Certification,” dated December 14, 2005. Approved in the SRM of December 30, 2005.

38. RG 1.32, “Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants.”

39. Intentionally left blank

40. RG 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 2, March 1997. (Revision 2, ADAMS Accession No. ML003761662)

41. RG 1.204, “Guidelines for Lightning Protection of Nuclear Power Plants,” Revision 0, November 2005.

42. RG 1.206, “Combined License Applications for Nuclear Power Plants (LWR Edition),” June 30, 2006.

43. NUREG-1784, “Operating Experience Assessment - Effects of Grid Events on Nuclear Power Plant Performance,” December 2003.

44. NUREG-1793, “Final Safety Evaluation Report Related to Certification of the AP1000 Standard Design,” September 2004.

45. Region IV Task Interface Agreement (TIA) No. 2002-03; Evaluation of Potential Unreviewed Safety Questions Associated with Modifications Made to Offsite Power at Cooper Nuclear Station (TAC No. MB5768).

46. IEEE Std. 242-2001, “Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems,” (Buff Book).

47. IEEE Std. 308-2001, "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

48. IEEE Std. 399-1997, "Recommended Practice for Power Systems Analysis," (Brown Book).

49. IEEE Std. 665-1995 (Reaffirmed 2001), "Guide for Generating Station Grounding."

50. IEEE Std. 666-2007, "Design Guide for Electric Power Service Systems for Generating Stations."

51. IEEE Std. 741-1997, "IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations."

52. IEEE Std. 765-1983, "IEEE Standard for Preferred Power Supply (PPS) for Nuclear Power Generating Stations." (2002 is latest revision)

53. IEEE Std. 1050-2004, "Guide for Instrumentation and Control Equipment Grounding in Generating Stations."

54. IEEE Std. C37.106 -2003, "Guide for Abnormal Frequency Protection for Power Generating Plants."

55. IEEE Std. C62.23-1995 (Reaffirmed 2001), "Application Guide for Surge Protection of Electric Generating Plants.

56. EPRI ALWR Utility Requirements Document, Volume II, "Evolutionary Plants," Chapter 11, "Electric Power Systems," Revision 6, December 1993, Electric Power Research Institute.

57. NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Section 11. Nuclear Energy Institute, February 11, 2000.

58. NRC Information Notice 2006-18, "Significant Loss of Safety-Related Electrical Power at Forsmark, Unit 1, in Sweden," August 17, 2006.

59. Economic Simplified Boiling-Water Reactor Final Safety Evaluation Report, March 10, 2011, ADAMS Accession No. ML103470210.

60. RG 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants," Revision 4, June 2013.

61. NRC Bulletin 2012-01. "Design Vulnerability in Electric Power System," U.S. Nuclear Regulatory Commission, July 2012, ADAMS Accession No. ML12074A115).

APPENDIX A

GUIDELINES FOR GENERATOR CIRCUIT BREAKERS/LOAD BREAK SWITCHES

1. Background

The term "Generator Circuit Breaker" (GCB), for the purpose of these guidelines, refers to circuit breakers located between the terminals of the main generator and the main step-up transformer and typically rated around 25-kV. Such GCBs have been used in nuclear generating station designs (McGuire, Catawba) as a means of providing immediate access of the onsite ac power systems to the offsite circuits by isolating the unit generator from the main step-up and unit auxiliary transformers and allowing backfeeding of power through these circuits to the onsite ac power system. Generator load break switches can also be used as a means of providing access to the offsite circuits, as described above, but only on a delayed basis. Since this is a new design feature, the staff made the use of GCBs and load break switches a generic safety issue (NUREG-0933, Item B-53). In the case of McGuire and Catawba, References A, B and C, an expert consultant was retained to evaluate the GCB verification testing program and its results. These guidelines formalize the results of that extensive work. Guidelines for the load break switches are also incorporated, as these devices have some common functional requirements as generator breakers, as described above.

The staff has made a determination that only those devices that have the capability of interrupting the system's maximum available fault current (i.e., circuit breakers) will be approved as a means of isolating the unit generators from the offsite power system to provide immediate access, in accordance with General Design Criterion (GDC) 17. This is necessary because a nonfault current interrupting device (i.e., load break switch), should delay its trip for electrical faults until the switchyard circuit breakers have interrupted the current. Following opening of the load break switch, the switchyard circuit breakers should then be reclosed to establish offsite power to the unit. A GCB, however, could interrupt the fault current and isolate the unit generator at the same time, maintaining continuous power to the onsite ac power system.

IEEE Std. C37-013 (Reference K) was issued to cover the ratings and required capabilities for ac high-voltage GCBs rated on a symmetrical current basis that are installed between the generator and the transformer terminals. Guidance for the application of GCBs is also given.

2. Specific Guidelines

A. Only devices that have maximum fault current interrupting capability (i.e., circuit breakers) can be used to isolate the unit generator from the offsite and onsite ac power systems to provide immediate access for the onsite ac power system to the offsite source. Generator load break switches can only be used for isolating the unit generator for the purpose of providing a delayed-access offsite source.

B. GCBs should be designed to perform their intended function during steady-state operation, power system transients, and major faults. The ratings and required capabilities of a generator circuit breaker are the designated limits of operating characteristics based on definite conditions as defined in IEEE Std. C37.013 (Reference K). This standard describes design test procedures and methods that should be performed to demonstrate the ability of a GCB to meet the assigned ratings when operating at a rated maximum voltage and power frequency. As a minimum, the following performance tests and capabilities from IEEE Std. C37.013 should be demonstrated:

i. <u>Rated Dielectric Strength</u>. The dielectric strength of a GCB should be demonstrated by subjecting it to high voltages, both the rated power frequency withstand voltage and the rated full wave impulse withstand voltage, based on its rated maximum voltage.

ii. <u>Load Current Switching</u>. Tests are made to determine the ability of the GCB to switch load current up to the rated continuous current of the generator, such as load currents that may be encountered in normal service. When switching the generator from the system, both GCB terminals remain energized. The power frequency recovery voltage appearing across the GCB is equal to the sum of voltage drops on the reactances of the generator and transformer and the corresponding short-circuit reactance of the high-voltage system.

    For applications that use only one GCB, the circuit breaker should be cycled through 40 load interruption operations (a lesser number requires suitable justification) at a current equal to the normal full-load continuous current rating of the circuit breaker. For applications that use two GCBs in a parallel circuit, the circuit breaker should be given 40 load interruption operations (a lesser number requires suitable justification) at a current equal to twice the normal full-load continuous current rating of the circuit breakers. The procedures and acceptance criteria used for this test should be based upon those given in IEEE Std. C37.013.

iii. <u>Short-Circuit Current Rating</u>. The rated short-circuit current is demonstrated by a series of symmetrical and asymmetrical tests, and close-open tests described in the standard. The rated symmetrical current should be the rated current value with the power frequency voltage associated with the rated maximum voltage and with a rated inherent transient recovery voltage, as described in IEEE Std. C37.013 for system-source faults and generator-source faults. The rated asymmetrical current-interrupting capability is demonstrated within the same conditions as the symmetrical current.

    The circuit breaker should have, as a minimum, the capability of interrupting the maximum asymmetrical and symmetrical fault current available at the instant of primary arcing contact separation. This current should be calculated by assuming a bolted three-phase fault at a point on the system that causes the maximum amount of fault current flowing through the GCB. The fault current interrupting capability (short-circuit current rating) of the circuit breaker should be demonstrated by performing a series of tests similar to those called for in IEEE

Std. C37.013. The tests should include close/open operations and should be performed at the circuit breaker minimum rated air pressure and control voltage and with a rated transient recovery voltage, as described in the standard for system-source faults and generator-source faults.

iv. Rated Transient Recovery Voltage (TRV). The ability to withstand rated TRVs, as specified in IEEE Std. C37.013 for rated symmetrical and asymmetrical currents, is demonstrated during short-circuit tests. Both inherent circuit TRV and power frequency recovery voltage should be considered when demonstrating the rating of a GCB. Additional information and guidance on TRV is provided in IEEE Std. C37.011 (Reference J).

v. Short-Time Current-Carrying Capability. The GCB shall be capable of carrying for a period of time Ts equals 1 second, any short-circuit current determined from the envelope of the current wave at the time of the maximum crest, the value of which does not exceed 2.74 times the rated short-circuit current, and whose rms value I, determined over the complete 1 second period, does not exceed the rated short-circuit current considered above.

The fault current chosen should be that due to a fault on the system at a point which causes the largest $I^2 t$ heating of the circuit breaker. The short-time current-carrying capability should be demonstrated with a current-carrying test as described in IEEE Std. C37.013. It is not to be inferred that the GCB is to be capable of interrupting after the required short-time current-carrying capability duty until it has cooled down to normal heat run temperature.

vi. Duty Cycle Capability. The duty cycle capability of the GCB should be demonstrated by a series of symmetrical and asymmetrical close-open cycle tests, as specified in IEEE Std. C37.013. The time between two operations to interrupt short-circuit current shall be the rated value of 30 minutes specified in the standard.

vii. Transformer Excitation Current Switching Tests. The circuit breaker interruption of an unloaded station main and/or auxiliary transformer excitation current should not generate excessively high surge voltages that could damage the connected bus and transformer insulation. This should be verified by a test.

viii. Rated Continuous Current-Carrying Test. The thermal capability of the circuit breaker should be demonstrated by a test at its continuous current rating. The test should be in accordance with the requirements and ratings contained in IEEE Std. C37.013. For applications that use two GCBs in a parallel circuit, a test should be conducted to determine the time to reach the maximum permissible temperature on the most limiting component of the breaker when going from a rated continuous current to a twice-rated continuous current.

ix. <u>Mechanical Endurance Life Test</u>. No-load mechanical operation tests are made on a complete GCB or on a single pole of the GCB, if all three poles are identical, to ensure its satisfactory operation in normal service without excessive maintenance. In practical applications, the GCB is connected to the bus duct by means of flexible copper or aluminum connections. The enclosure of the GCB may be welded to the enclosure of the bus duct. These conditions should be taken into account during the tests. A sufficient number of no-load mechanical operations should be performed by the circuit breaker to provide a reasonable indication of its mechanical reliability and life. The demonstrated life should be adequate for the plant life expectancy.

x. <u>Rated Interrupting Time</u>. The rated interrupting time of the GCB is the maximum permissible interval between the energizing of the trip circuit at rated control voltage and rated fluid pressure of the operating mechanism and the interruption of the main circuit in all poles on an opening operation. Typical values are approximately 60–90 ms with the actual time being dependent on the rated short-circuit current. For GCBs equipped with resistors, the interrupting time for the resistor current may be longer. The interrupting time of a GCB is demonstrated for different currents by the test duty cycles specified in IEEE Std. C37.013. Interrupting times of test results, when expressed in cycles, shall be in cycles of the power frequency.

xi. <u>Short-Circuit Current with Delayed Current Zero</u>. It is generally accepted that the GCB will be required, during its life, to interrupt short-circuit currents from the generator-source with delayed current zeros. It is also recognized that the magnitudes of these short-circuit currents are considerably lower than the magnitudes of the rated short-circuit currents. The capability of the GCB to interrupt the delayed current zeros can be ascertained by computations that consider the effect of the arc voltage on the prospective short-circuit current. The determining arc voltage model is derived from tests with comparable magnitudes of current.

If this computation entails too many assumptions on the behavior of the GCB during interruption under the most severe conditions, short-circuit tests shall be required. If tests are carried out, it should be recognized that, normally, the required current wave shape cannot be simulated accurately in test stations. Tests should include a predetermined nonzero current waveform associated with the rated maximum voltage and an inherent circuit TRV, and an approximate waveform obtained either by calculation or by measurement at the GCB's particular application.

C. The availability of offsite power to the onsite loads for designs using GCBs should be no less than comparable designs that use separate offsite power transformers to supply offsite power to the station loads. In this regard, the trip selectivity between the GCBs and the switchyard high-voltage GCBs should ensure against unnecessary tripping of the switchyard GCBs during abnormal events to maintain offsite power to the station loads.

D. Load break switches should be designed to perform their intended function during steady-state operation, power system transients, and major faults. Except for Item 2.C, the switches should have the same capabilities as defined in Guideline 2 for GCBs. In addition, the symmetrical interrupting capability of the load break switch should be at least equal to the maximum identified peak loading capability of the station generator.

3. References for Appendix A to DSRS Section 8.2

A. SER related to operation of McGuire Nuclear Station, Units 1 and 2, NUREG-0442, dated March 1978.

B. FSAR McGuire Nuclear Station Docket 50-396/370.

C. FSAR Catawba Nuclear Station Docket 50-413/414.

D. IEEE Std. C37.04-1999, Standard Rating Structure for AC High-Voltage Circuit Breakers.

E. IEEE Std. C37.04a-2003, Standard Rating Structure for AC High-Voltage Circuit Breakers rated on a Symmetrical Current Basis – Amendment 1: Capacitance Switching Current.

F. ANSI Std. C37.06-2000, AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis-Preferred Ratings and Related Required Capabilities.

G. IEEE Std. C37.09-1999, Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

H. IEEE Std. C37.09a-2005, Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Amendment 1: Capacitance Switching Current.

I. IEEE Std. C37.010-1999, Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

J. IEEE Std. C37.011-2005, Application Guide for Transient Recovery Voltage for AC High-Voltage Circuit Breakers.

K. IEEE Std. C37.013-1997, Standard for AC High-Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis.