UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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ATLANTA, GEORGIA 30303-1257

November 7, 2014

MEMORANDUM TO: Aby S. Mohseni, Deputy Director
Division of Policy and Rulemaking
Office of Nuclear Reactor Regulation

FROM: Terrence Reis, Director /RA/
Division of Reactor Safety

SUBJECT: REQUEST FOR TECHNICAL ASSISTANCE REGARDING THE ADEQUACY OF THE OCONEE STATION DESIGN AND LICENSING BASES FOR THE DEGRADED VOLTAGE RELAY PROTECTION DESIGN (TIA 2014-04)

The purpose of this Task Interface Agreement (TIA) is to formally request assistance from the Office of Nuclear Reactor Regulation (NRR) to conduct a technical assessment of the adequacy of the licensing and design bases relative to the Oconee Nuclear Station (ONS) degraded voltage relay (DVR) protection design, and to determine whether the methodology used in the ONS offsite/station electric power system design meets U.S. Nuclear Regulatory Commission (NRC) requirements.

Background

On May 9, 2014, NRC Region II completed a Component Design Bases Inspection (CDBI) at ONS (ADAMS Accession No. ML 14178A535). During the inspection, the CDBI team identified a question involving the adequacy of the licensee's DVR protection design and licensing bases, which was documented in the NRC CDBI Report as Unresolved Item 05000269, 270, 287/2014007-04, "Degraded Voltage Relay Scheme." During the inspection, the CDBI team identified the following potential issues:

Issue 1: Each Oconee unit has six available sources of power to the engineered safeguards systems, which include the two Keowee Hydro Units, the 230 kV transmission system and/or the 525 kV transmission system, the 100 kV transmission system, and the two other nuclear units that are supplied to the unit auxiliary transformers through the switchyard.

The CDBI team noticed that the DVR configuration (second level undervoltage protection) at ONS was not located on the Class 1E 4.16 kV safety buses, and that the loss of voltage (LOP) relays (first level undervoltage protection) are relied upon for monitoring the Class 1E 4.16 kV safety buses to disconnect from offsite power and subsequently re-connect to the Keowee Hydro Units to meet the Chapter 15 plant accident analyses. The DVR configuration is located on the 230 kV switchyard Yellow bus and on Transformer CT5 when the Central 100 kV

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switchyard is energizing the standby buses in operation modes 1-4. As a result of the DVR configuration being located on the 230 kV switchyard Yellow bus and on Tranformer CT5 when the Central 100 kV switchyard is energizing the standby buses, a second level of undervoltage protection for the 4.16 kV safety buses is not provided during normal operation when the 4.16 kV safety buses are fed from the unit auxiliary transformers.

In a letter to the licensee dated June 3, 1977 (Reference 1), the NRC requested that the licensee compare the current design of the emergency power systems with the staff positions stated in the Enclosure to the letter and either (1) propose plant modifications as necessary to meet the staff positions, or (2) provide a detailed analysis which showed that the facility design had equivalent capabilities and protective features. These actions were required to assess the susceptibility of the safety-related electrical equipment with regard to (1) sustained degraded voltage conditions at the offsite power sources, and (2) interaction between the offsite and onsite emergency power systems.

Position 1 of the NRC letter to the licensee dated June 3, 1977, stated, in part, that "We require that a second level of undervoltage protection for the onsite power system be provided" and that the time delay of this second level of undervoltage protection shall ensure that the allowable time duration for a degraded voltage condition at all distribution system levels shall not result in failure of safety systems or components.

The licensee responded in a letter to the NRC dated July 21, 1977 (Reference 2), stating that the existing undervoltage (loss of voltage) protection system on the feeders that supplied power to the safety-related buses had equivalent capabilities and protection features to those described in the staff's position (in the June 3, 1977, letter). As stated in the letter, this was due to the relatively high DVR set points of 88 percent of rated bus voltage and design, which features a two-out-of-three coincident logic tripping scheme with inverse time characteristics.

The NRC, in a letter to the licensee dated December 20, 1978 (Reference 3), documented a review of the existing undervoltage protection system at ONS and determined that the design afforded adequate protection against degraded grid undervoltage conditions in accordance with the NRC letter of June 3, 1977, and was therefore acceptable. In a letter dated October 7, 1977 (Reference 4), the licensee submitted a proposed amendment to incorporate technical specifications (TS) comparable to those in the staff position.

As a result of design deficiencies identified in licensee event report (LER) 269/90-04 (Reference 5) and LER 269/90-05 (Reference 6), in a letter to the NRC dated May 8, 1990 (Reference 7), the licensee proposed a modification to the plant to install degraded voltage protection relaying on the 230 kV switchyard Yellow bus. On June 6, 1990, a conference call between the licensee and the NRC staff was held, during which the NRC staff brought up a concern about the impact of degraded voltage on safety-related equipment during normal plant operation. In a letter to the NRC dated June 18, 1990 (Reference 8), the licensee provided a response to address the concern and to credit the existing undervoltage (loss of voltage) protection system on the feeders to the main feeder buses that supply power to the safety-related buses for adequate protection during normal power operation. The NRC approved this position for the proposed degraded grid protection in a safety evaluation report (SER) dated November 14, 1990 (Reference 9).

<u>Issue 2</u>: For degraded voltage detected on the 230 kV switchyard Yellow bus with no accident signal present, the DVR alarm in the main control room results in manual actions to resolve the degraded voltage condition, or to disconnect from the degraded source. Licensee operators,

upon receipt of the low voltage alarm on the 230 kV Yellow bus, enter procedure AP/1/A/1700/034, “Degraded Grid.” Based on an operator simulated, timed evaluation of the scenario, it would take approximately 12.5 minutes for licensee operators to initiate separation from the grid due to the degraded condition.

The NRC letter to the licensee dated June 3, 1977 (Reference 1), stated, in part, that “We require that a second level of undervoltage protection for the onsite power system be provided” and that this second level of undervoltage protection shall ensure “That the voltage monitors shall automatically initiate the disconnection of offsite power sources whenever the voltage set point and time delay limits have been exceeded.”

In a letter to the NRC dated May 8, 1990 (Reference 7), the licensee proposed a modification to the plant to install degraded voltage protection relaying to the 230 kV switchyard Yellow bus to resolve design deficiencies identified in LER 269/90-04 and LER 269/90-05. The letter stated that the proposed logic would provide inputs for alarms, and would initiate switchyard isolation if an engineered safeguards (ES) signal is present on any of the three units. In a response to the NRC staff in a conference call conducted in 1990, the licensee stated that after a degraded grid alarm is received, steps would be taken to re-establish an adequate voltage level on the grid.

The NRC issued an SER for the proposed degraded grid protection in a letter to the licensee dated November 14, 1990 (Reference 9), in which the staff found the proposed degraded grid protection modification acceptable. The SER stated that the undervoltage condition in itself does not result in the separation of the Class 1E distribution system from the offsite grid (i.e., an ES signal must exist coincidentally before the undervoltage protective action occurs). The SER further stated that the licensee’s proposed modification did not fully meet Branch Technical Position (BTP) PSB-1 in several areas. However, the NRC, in the past, had permitted the use of alarms, procedures, and manual operator actions in lieu of automatic actions to ensure that the safety-related components of the Class 1E systems would not be adversely affected during low voltage conditions for plants in the Northeast. The SER concluded that ONS may have similar weaknesses to what existed in the Northeast, and that it would not be prudent to impose the complete requirements of the BTP.

<u>Issue 3</u>: The licensee credits operation of the LOP relays (first level undervoltage protection) for monitoring the 4.16 kV main feeder buses to disconnect from offsite power on a loss of voltage condition, and subsequently re-connect to the Keowee Hydro Units to meet the Chapter 15 plant accident analyses. However, the LOP relay setpoints and associated time delays are not included in the plant TS.

The NRC staff position for compliance with 10 CFR Part 50.36 for Babcock and Wilcox (B&W) Plants is contained in NUREG-1430, “Standard Technical Specifications Babcock and Wilcox Plants,” which included Standard Technical Specification (STS) 3.3.8, “Emergency Diesel Generator (EDG) Loss of Power Start (LOPS).” The bases section of STS 3.3.8 stated that the EDG LOPS is required for the engineered safety features (ESF) to function in any accident with a loss of offsite power. The EDG LOPS design bases relies on the ESF actuation system and its channels to satisfy requirements of 10 CFR 50.36(c)(2)(ii). The licensee indicated in their justification for deviation that comparable requirements would be added to Improved Technical Specification (ITS); however, the licensee did not include the LOP relays in the ITS other than for a channel check function.

Licensee Position

Issue 1: The licensee stated in a letter to the NRC dated July 21, 1977 (Reference 2), that the existing undervoltage (loss of voltage) protection system on the feeders that supply power to the safety-related buses had equivalent capabilities and protection features to those described in the staff's position (in the June 3, 1977, letter) due to their relatively high set points of 88 percent of rated bus voltage and design which features a two-out-of-three coincident logic tripping scheme with inverse time characteristics. In a letter to the NRC dated June 18, 1990 (Reference 8), the licensee credited the existing undervoltage (loss of voltage) protection system on the feeders to the main feeder buses that supply power to the safety-related buses for adequate protection during normal power operation.

Issue 2: The licensee's position, as stated in sections 4.c-3 and 4.d of the ONS Degraded Voltage Position Paper (Reference 10), is that the Degraded Grid Undervoltage (DGUV) system will isolate the switchyard and start the Keowee Hydro Units in the event of an ES system actuation during the degraded grid condition and that any proceduralized manual actions for the DGUV alarms are only preliminary actions since the Class 1E buses are automatically protected by the LOP (first level undervoltage protection) relays, which ensure that the safety-related equipment have adequate voltage to start and survive if needed for an ES actuation. In a conference call with NRR conducted in 1990, the licensee stated that after a degraded grid alarm is received, steps would be taken to re-establish an adequate voltage level on the grid. The NRC staff stated in the SER that the licensee's proposed modification did not fully meet BTP PSB-1; however, the staff found the proposed degraded grid protection modification acceptable due to weaknesses during low voltage conditions similar to those at plants in the Northeast.

Issue 3: The licensee's position, as stated in section 4.f of the ONS Degraded Voltage Position Paper (Reference 10), is that 10 CFR 50.36 (c)(2)(iii) states that a licensee is not required to propose to modify TS that are included in any license issued before August 18, 1995, to satisfy the criteria in paragraph (c)(2)(ii) of this section. As such, ONS was not required to modify TS to include items that met Criterions 1,2,3, and 4 since the ONS Operating License and TS were issued in the early 1970's. In addition, the licensee in Attachment 5, "Justification for Deviation," in the ONS ITS Conversion, stated, "NUREG LCO 3.3.8, EDG LOPS, is not adopted since it is not applicable to ONS. ONS does not use EDGs for emergency power. Comparable ITS requirements related to the Keowee Hydro Units, which are used at ONS for emergency power, are included in ITS 3.3.19."

Regulatory and Technical Issues

Issue 1: Atomic Energy Commission (AEC) Principal Design Criterion 39, "Emergency Power for Engineered Safety Features," required alternate power systems be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the ESF. As a minimum, the onsite power system and the off-site power system shall each, independently, provide this capacity assuming a failure of a single active component in each power system.

Position 1 of the NRC letter to the licensee dated June 3, 1977 (Reference 1), stated, in part, that "We require that a second level of undervoltage protection for the onsite power system be provided" and that the time delay of this second level of undervoltage protection shall ensure that the allowable time duration for a degraded voltage condition at all distribution system levels shall not result in failure of safety systems or components.

Regulatory Issue Summary (RIS) 2011-12, “Adequacy of Station Electric Distribution System Voltages,” stated that the NRC letter to the licensee dated June 3, 1977, provided guidance which applied to all operating reactors at that time and plants licensed since, on how to comply with the requirements in 10 CFR Part 50, Appendix A, GDC 17, “Electric Power Systems.” The design criteria for ONS was developed in consideration of the seventy general design criteria proposed by the AEC in 1967. AEC Principal Design Criterion 39 contained similar requirements to that of 10 CFR Part 50, Appendix A, GDC 17.

The CDBI team noticed that the DVR configuration at ONS was not located at the 4.16 kV safety buses, which would result in a lack of second level undervoltage protection for the ESF during normal operation when the 4.16 kV safety buses are fed from the unit auxiliary transformers.

Issue 2: Title 10 CFR Part 50.55a(h)(2) “Protection Systems,” states, “For nuclear power plants with construction permits issued after January 1, 1971, but before May 13, 1999, protection systems must meet the requirements stated in either IEEE Std-279, "Criteria for Protection Systems for Nuclear Power Generating Stations," or in IEEE Std-603-1991, "Criteria for Safety Systems for Nuclear Power Generating Stations," and the correction sheet dated January 30, 1995. For nuclear power plants with construction permits issued before January 1, 1971, protection systems must be consistent with their licensing bases or may meet the requirements of IEEE Std. 603-1991, and the correction sheet dated January 30, 1995.”

Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” states that measures shall be established to assure that applicable regulatory requirements and the design bases, as defined in 10 CFR Part 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. Section 7.1.2.1 of the UFSAR, “Design Bases,” stated that the protective systems met the intent of the proposed IEEE “Criteria for Nuclear Power Plant Protection Systems” dated August 1968. Section 4.1 of IEEE 279-1968 stated that the nuclear power generating station protection system shall, with precision and reliability, automatically initiate appropriate protective action whenever a condition monitored by the system reaches a preset level. This requirement applies for the full range of conditions and performance enumerated in Sections 3(7), 3(8), and 3(9). Section 3(7) details the sensors used to monitor the range of transient and steady state conditions of the energy supplies (for example, voltage).

The use of manual actions for a degraded voltage condition is contrary to the principal design criteria stated in AEC Criterion 39. The NRC letter to the licensee dated June 3, 1977 (Reference 1), and later incorporated into BTP PSB-1, stated, in part, that “We require that a second level of undervoltage protection for the onsite power system be provided” and that this second level of undervoltage protection shall ensure “That the voltage monitors shall automatically initiate the disconnection of offsite power sources whenever the voltage set point and time delay limits have been exceeded.” The NRC letter to the licensee dated June 3, 1977, also stated the voltage monitors of this second level of protection shall be designed to satisfy the requirements of IEEE 279-1971, which were similar to the requirements in IEEE 279-1968 for automatic protection as discussed earlier.

The use of manual actions for a degraded voltage condition is not approved in Regulatory Issue Summary 2011-12, “Adequacy of Station Electric Distribution System Voltages,” which states, “During normal plant operation, the Class 1E safety-related buses should automatically separate from the power supply within a short interval if sustained degraded voltage conditions are detected."

Issue 3: The licensee credits operation of the LOP relays for monitoring the 4.16 kV main feeder buses to disconnect from offsite power on a loss of voltage condition, and to subsequently re-connect to Keowee Hydro to meet the Chapter 15 plant accident analyses. However, the LOP relay set points and associated time delays are not included in the plant TS. This appears to be contrary to 10 CFR Part 50.36(c)(2)(ii)(C), "Criterion 3."

The regulations under 10 CFR Part 50.36, "Technical Specifications," Section (b) require, in part, that "The technical specifications will be derived from the analyses and evaluation included in the safety analysis report, and amendments thereto, submitted pursuant to Section 50.34." Title 10 CFR Part 50.36(c)(2)(ii)(C) states, in part, that a TS limiting condition for operation of a nuclear reactor must be established for a structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design bases accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

Oconee ITS 3.3.19, "Emergency Power Switching Logic (EPSL) 230 kV Switchyard Degraded Grid Voltage Protection (DGVP)," only addresses the degraded voltage relays, whose set points, and associated time delays, are included in SR 3.3.19.2. Oconee ITS 3.3.18, "Emergency Power Switching Logic (EPSL) Voltage Sensing Circuits," addresses the LOP sensing circuits associated with the (1) Startup Transformer, (2) Auxiliary Transformer, and (3) Standby Buses 1 and 2. Surveillance requirement SR 3.3.18.1 only performs a channel functional test, and does not include any set point settings or associated time delays.

The CDBI team noted that B&W NUREG-1430 indicated that the LOP relay set points and associated time delays be included in the ITS. The licensee indicated, in their justification for deviation, that comparable requirements would be added to ITS, but failed to do so. The licensee credits operation of the LOP relays monitoring the 4.16 kV main feeder buses to disconnect from offsite power on a loss of voltage condition, and subsequently reconnect to the Keowee Hydro Units to meet the Chapter 15 plant accident analyses. However, contrary to the requirements of 50.36(c)(2)(ii)(C), the LOP relay set points and associated time delays, were not included in the plant TS.

Requested Action

Region II requests that NRR consider the following issues while conducting their review. Specifically:

1. Is Oconee's existing DVR protection configuration (second level undervoltage protection scheme) and offsite/station electric power system design adequate for meeting NRC regulations and the ONS licensing bases (e.g., AEC Principal Design Criterion 39; 10 CFR Part 50.55a(h)2; 10 CFR Part 50, Appendix B, Criterion III; the June 3, 1977, letter; etc.)? (Issues 1, 2, and 3)

2. Do the automatic actions of the LOP relays (first level undervoltage protection scheme) meet the intent of the DVR protection scheme (second level undervoltage protection scheme), as stated in the licensee's letters of July 21, 1977, and June 18, 1990. (Issues 1, 2, and 3)

3. Does the licensee's use of manual actions for a degraded voltage signal detected on the 230 kV switchyard Yellow bus with no accident signal present meet NRC requirements and regulations (e.g., 10 CFR Part 50.55a(h)(2); 10 CFR Part 50, Appendix B, Criterion III; the June 3, 1977, letter; etc.)? (Issue 2)

4. Do the current TS meet the requirements of 10 CFR 50.36(c)(2)(ii)(C), "Criterion 3," which states, in part, that a TS limiting condition for operation of a nuclear reactor must be established for a structure, system, or components that is part of the primary success path, and which functions or actuates to mitigate a design bases accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier? (Issue 3)

5. If the TS and/or design configuration of the plant are inadequate, how should the NRC proceed to ensure the licensee is operating in accordance with NRC regulations (e.g., NRC Administrative Letter 98-10 or backfit)? (Issues 1, 2, and 3)

Coordination
This request was discussed during a conference call on July 14, 2014, between Marcus Riley (RII/DRS/EB1), Holly Cruz, (PM Lead (NRR/DPR/PLPB), and other NRR staff. The TIA was accepted by NRR with an agreed-upon draft response date of nine months from the date of this TIA request. In addition, the NRR staff discussed circumstances that would necessitate review and concurrence by the Office of General Counsel. If such concurrence is warranted, NRR will coordinate this review.

References

1. NRC letter to Duke Power Company concerning implementation of second level undervoltage protection dated June 3, 1977, (ADAMS Accession No. ML14231B281)
2. Duke Power Company Degraded Voltage Response dated July 21, 1977, (ADAMS Accession No. ML14231B282)
3. NRC Acceptance of ONS DVR Design dated December 20, 1978, (ADAMS Accession No. ML14231B293)
4. ONS Degraded Voltage LAR Submittal dated October 7, 1977, (ADAMS Accession No. ML14231B295)
5. LER 269/90-04 (ADAMS Accession No. ML14231B296)
6. LER 269/90-05 (ADAMS Accession No. ML14231B299)
7. Switchyard Degraded Voltage letter dated May 8, 1990, (ADAMS Accession No. ML14231B300)
8. Switchyard Degraded Voltage RAI dated June 18, 1990, (ADAMS Accession No. ML14231B302)
9. SER on Degraded Grid Modification dated November 14, 1990, (ADAMS Accession No. ML14231B303)
10. ONS Degraded Voltage Position Paper (ADAMS Accession No. ML14259A593)
11. Oconee Nuclear Station, Units 1, 2 and 3, NRC Component Design Bases Inspection Report, 05000269, 270, 287/2014007 (ADAMS Accession No. ML 14178A535)
12. Regulatory Issue Summary 2011-12, Adequacy of Station Electric Distribution System Voltages, Rev. 1
13. NUREG-1430, Standard Technical Specifications Babcock and Wilcox Plants
14. IEEE Std-279-1968, "Criteria for Protection Systems for Nuclear Power Generating Stations"
15. IEEE Std-603-1998, "Criteria for Safety Systems for Nuclear Power Generating Stations"

November 7, 2014

MEMORANDUM TO: Aby S. Mohseni, Deputy Director
Division of Policy and Rulemaking
Office of Nuclear Reactor Regulation

FROM: Terrence Reis, Director **/RA/**
Division of Reactor Safety

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(*) – SEE PREVIOUS PAGE FOR CONCURRENCES

☐ PUBLICLY AVAILABLE x☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE x☐ NON-SENSITIVE

ADAMS:x ☐ Yes ACCESSION NUMBER:_ML14311A862______________ ☐ SUNSI REVIEW COMPLETE ☐ FORM 665 ATTACHED

OFFICE	RII:DRS	RII:DRS	RII:DRS	RII:DRS	RII:DRS		
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DATE	10/28/2014	10/29/2014	10/29/2014	10/30/2014	11/7/2014	11/ /2014	11/ /2014
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