UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

January 22, 2019

MEMORANDUM TO: Anthony T. Gody, Director
Division of Reactor Safety
Region II

FROM: Gregory F. Suber, Deputy Director ***/RA/***
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

SUBJECT: OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3 - RESPONSE TO TASK INTERFACE AGREEMENT 2014-04, ADEQUACY OF THE OCONEE NUCLEAR STATION DESIGN AND LICENSING BASES FOR DEGRADED VOLTAGE PROTECTION (TAC NOS. MF4622, MF4623, AND MF4624; EPID L-2014-LRA-003)

By Task Interface Agreement (TIA) 2014-04 dated November 7, 2014 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML14311A862), as revised by electronic mail (email) dated July 27, 2018 (ADAMS Accession No. ML18211A217), U.S. Nuclear Regulatory Commission (NRC) Region II requested assistance from the Office of Nuclear Reactor Regulation (NRR) regarding the Oconee Nuclear Station, Unit Nos. 1, 2, and 3 (Oconee) degraded voltage relay (DVR) protection design and licensing basis.

The NRR staff has reviewed this matter and determined that DVRs not being installed on the 4.16-kilovolt safety buses fed by the unit auxiliary transformers during normal operation, the use of manual actions during mitigation of degraded voltage conditions, and the loss-of-power relay setpoints and time delays not being in Technical Specifications are consistent with the Oconee licensing basis and applicable NRC staff positions for Oconee. The basis for this conclusion is provided in the enclosed TIA response. The conclusion presented in this TIA response represents the NRC staff position for Oconee but is not generic and does not apply directly to other licensees or sites.

Enclosure:
Response to TIA 2014-04

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ADAMS Accession No.: ML18226A215; *concurred via e-mail

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OFFICE OF NUCLEAR REACTOR REGULATION

RESPONSE TO TASK INTERFACE AGREEMENT 2014-04

REGARDING DEGRADED VOLTAGE RELAY PROTECTION

OCONEE NUCLEAR STATION UNITS 1, 2, AND 3

DOCKET NOS. 05000269, 05000270, AND 05000287

1.0 INTRODUCTION

On May 9, 2014, the U.S. Nuclear Regulatory Commission (NRC) Region II Office (Region II) staff completed a Component Design Bases Inspection (CDBI) at Oconee Nuclear Station (Oconee). Duke Energy Carolinas, LLC is the licensee for Oconee. During the inspection, the inspectors identified several concerns regarding the adequacy of the licensee's degraded voltage relay (DVR) protection design and licensing bases. These concerns are documented in Unresolved Item 2014007-04, "Degraded Voltage Relay Scheme," from the CDBI Report No. 05000269/2014007, 05000270/20140007, and 05000287/2014007, dated June 27, 2014 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML14178A535). To resolve these concerns, Region II developed Task Interface Agreement (TIA) 2014-04, dated November 7, 2014 (ADAMS Accession No. ML14311A862), to request assistance from the Office of Nuclear Reactor Regulation (NRR).

In its TIA, Region II staff described concerns about aspects of the licensee's protection from degraded and loss of voltage conditions – that DVRs are not installed on the 4.16-kilovolt (kV) safety buses during normal operation when those buses are fed from the unit auxiliary transformers (UATs), that the licensee uses manual actions during mitigation of degraded voltage conditions, and that loss-of-power (LOP) relays are used for monitoring safety-related buses, but relay setpoints and time delays are not in the Technical Specifications (TSs).

By electronic mail (email) dated July 27, 2018 (ADAMS Accession No. ML18211A217), Region II staff revised its request by modifying the scope of the TIA and requesting NRR staff to clarify whether the issues discussed in the TIA are consistent with the Oconee licensing basis and staff positions applicable to Oconee.

2.0 BACKGROUND

2.1 CDBI Unresolved Item

Section 1R21.2.b.iv of the aforementioned CDBI report describes Unresolved Item 2014007-04 and states:

> Introduction: The team identified an unresolved item to determine whether a performance deficiency exists with respect to the licensee's [DVR] scheme.
>
> Description: The team identified that the licensee's [DVRs] did not monitor the safety-related 4.16 kV buses, but rather they monitored the switchyard 230 kV Yellow bus. This resulted in a lack of degraded voltage protection whenever the 4.16 kV safety-related buses were not being fed through the start-up

transformers. During normal power operation, the 4.16 kV safety-related buses were supplied from the [UATs]. Additionally, for degraded voltage detected on the 230 kV switchyard Yellow bus with no accident signal present, the [DVR] alarm in the main control room would have only resulted in manual actions to resolve the degraded voltage condition or to disconnect from the degraded source. It was estimated that the manual actions could take as long as 12 minutes to resolve the degraded voltage condition. The use of [DVRs] only on the 230 kV switchyard Yellow bus and the use of manual actions for a degraded voltage condition appeared to be contrary to the design criteria for degraded voltage protection stated in an NRC letter to the licensee dated June 3, 1977 and NRC Regulatory Issue Summary 2011-12. Lastly, the team identified that Oconee currently credits operation of the loss-of-voltage relays monitoring the 4.16 kV main feeder buses [MFBs] to disconnect from offsite power on a loss of voltage condition and subsequent re-connection to Keowee Hydro to meet the UFSAR [Updated Final Safety Analysis Report] Chapter 15 plant accident analyses. However, the loss of voltage relay setpoints and associated time delays were not included in the plant TS. This appeared to be contrary to 10 CFR 50.36(c)(2)(ii)(C) [Title 10 of the *Code of Federal Regulations,* Section 50.36(c)(2)(ii)(C)] Criterion 3.

The team determined that consultation with [NRR] was warranted for the NRC to determine: (1) whether Oconee's existing licensing and design bases are adequate and meet all NRC regulations and requirements with their current [DVRs] design and off-site/station electric power system design, (2) whether the automatic actions for the loss-of-voltage relays meet the intent of the [DVRs], and (3) whether the current plant TS meet the requirements of 10 CFR 50.36(c)(2)(ii)(C) which state, in part, that a TS limiting condition for operation [LCO] 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 basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. The licensee entered this issue into their corrective action program as PIP O-14-2034. This issue is being tracked as [Unresolved Item] 05000269/2014007-04, 05000270/2014007-04, 05000287/2014007-04, Degraded Voltage Relay Scheme.

2.2 Licensee's Position Paper

In response to Region II's concerns raised during the inspection, the licensee submitted letter ONS-2015-065 dated May 22, 2015 (ADAMS Accession No. ML15154A490), to the NRC and provided additional information to aid the NRC staff in completing its review of the concerns raised by the Region II staff. The NRC staff examined the statements in the licensee's letter but did not take any regulatory action, including the creation of staff positions, regarding the subject letter.

2.3 TIA Request

In its TIA request as revised, Region II staff requested NRR to answer the following question (the bases for the Region II staff's concerns are discussed in Section 4 of this TIA response).

> Are the situations discussed in the TIA Background section, under Issues 1, 2, and 3, consistent with the Oconee licensing basis and applicable staff positions for Oconee? Issues 1, 2, and 3 are summarized as follows:
>
> 1. DVRs are not installed on the 4.16-kV safety buses during normal operation when those buses are fed from the UATs.
> 2. The licensee uses manual actions during mitigation of degraded voltage conditions.
> 3. LOP relay setpoints and time delays are not in the TSs.

3.0 REGULATORY REVIEW

3.1 NRR's Method of Review

The NRR staff reviewed licensing basis information and docketed correspondence to determine whether TIA Issues 1, 2, and 3 are consistent with Oconee's licensing basis and NRC staff positions applicable to Oconee. The staff reviewed regulations, plant-specific design-basis information as documented in the UFSAR (ADAMS Accession No. ML18192A809), commitments and responses to generic communications, amendments to the operating licenses, and TSs. The NRR staff also reviewed staff positions in NRC safety evaluations (SEs) and correspondence to the licensee.

3.2 Design Basis as Described in the UFSAR

Section 8.2.1.3.1 of the UFSAR states that two channels of degraded grid protection are provided to assure that the degradation of the voltage from offsite sources does not adversely impact the safety function of safety-related systems and components. Each channel of this system, upon detection of inadequate voltage, will provide an alarm to alert control room personnel of the existence of inadequate voltage in the 230-kV switchyard. If an engineered safety feature signal is sensed by the degraded grid protection system, while the voltage is sustained below acceptable levels, the degraded grid protection system will initiate an isolation of the 230-kV switchyard (i.e., of the yellow bus) and start the Keowee Hydro Units (KHUs) so that the onsite emergency overhead power path is available. The Oconee units operating without an engineered safety feature signal present will not be affected by this action and will continue to operate because their generators remain connected to the 230-kV switchyard (i.e., to the red bus). Section 8.2.1.3.1 of the UFSAR states that it is anticipated that any degradation of the voltage in the 230-kV switchyard will not last for an extended period of time, that it is recognized that the voltage in the switchyard needs to be maintained above acceptable levels, and that corrective measures would be taken to assure that timely actions are taken to restore the voltage.

Section 8.2.1.3.1 of the UFSAR states that there are three single-phase undervoltage relays installed to monitor the switchyard voltage on the X, Y, and Z phases of the 230-kV yellow bus. Each of the undervoltage relays is connected to one of three single-phase coupling capacitor voltage transformers. The setpoint of the undervoltage relays considers the minimum analyzed

switchyard voltage and the cumulative tolerances of the undervoltage relays and the voltage sensing devices. A time delay is provided to override transients in the offsite system and prevent unnecessary actuation of this protection system.

3.3 Correspondence Regarding Degraded Voltage Protection

In its letter dated June 3, 1977 (ADAMS Accession No. ML15209A375), the NRC staff requested the licensee to compare its design of the emergency power systems to the staff positions stated in the Enclosure 1 to the letter and either propose plant modifications, as necessary, to meet the staff positions, or provide a detailed analysis that showed that the facility design had equivalent capabilities and protective features. The staff also requested that certain TSs be incorporated into operating licenses and included model TSs consistent with the Enclosure 1 staff positions in Enclosure 2 of the letter. The staff requested these actions so that it could assess the susceptibility of the safety-related electrical equipment with regard to sustained degraded voltage conditions at the offsite power sources and interaction between the offsite and onsite emergency power systems. Position 1 of this letter stated, in part, that the NRC requires 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.

In its letter dated July 21, 1977 (ADAMS Accession No. ML16030B655), the licensee responded, in part, to the NRC's letter and stated that the existing undervoltage (i.e., LOP) protection system on the feeders that supplied power to the safety-related buses had equivalent capabilities and protection features to those described in Position 1 of the NRC letter dated June 3, 1977, because of the relatively high inverse-time first level undervoltage protection relays setpoint of 88 percent of rated bus voltage and design, which features a two-out-of-three coincident logic tripping scheme with inverse time characteristics.

By letter dated October 7, 1977 (ADAMS Accession No. ML16030A284), the licensee submitted an additional response to the NRC's letter dated June 3, 1977, and proposed an amendment to incorporate TSs comparable to those in the position of the NRC's letter. The licensee proposed to add TSs for startup voltage sensing circuits. The NRR staff was unable to locate any record of the NRC processing this amendment request or of the licensee withdrawing the request. Subsequent amendments to the same TS pages indicate that the changes proposed in the application dated October 7, 1977, had not been incorporated into the TSs. However, the NRC issued amendments to the licensee in 1982 that included new TSs for the Emergency Power Switching Logic (EPSL), which included requirements for the startup voltage sensing circuits. The NRC also issued amendments to the licensee in 1998 that added TSs for the DVRs, including degraded voltage channel testing requirements for the EPSL circuits. Section 3.4 of this TIA response discusses these amendments in more detail.

In its letter to the licensee dated December 20, 1978 (ADAMS Accession No. ML16134A619), the NRC staff documented its review of Oconee's undervoltage protection design, referenced the licensee's letters dated July 21, and October 7, 1977, and determined that the design afforded adequate protection against degraded grid undervoltage conditions in accordance with the NRC letter of June 3, 1977, and, therefore, was acceptable.

In NRC Generic Letter 79-36 dated August 8, 1979 (ADAMS Legacy No. 7908230155; https://www.nrc.gov/reading-rm/doc-collections/gen-comm/gen-letters/1979/gl79036.html), the NRC staff requested power reactor licensees to review the electric power systems at their

nuclear power plants to determine the capacity and capability of the offsite power system and the station electric power system to automatically start and run all required safety-related loads assuming onsite alternating current (AC) power sources are not available. For Oconee, this effort culminated in the issuance of Amendment Nos. 127, 127, and 124 for Units 1, 2, and 3, respectively, on March 2, 1984, which are discussed in the next subsection of this review.

In Licensee Event Reports (LERs) 269/90-04 and 269/90-05 dated April 30, and May 24, 1990 (ADAMS Accession Nos. ML15224A148 and ML15224A150, respectively), the licensee described an unanticipated system interaction during an undervoltage condition in the 230-kV switchyard that resulted in a failure to comply with TSs. In the LERs, the licensee indicated that the cause of the issue was the undervoltage relay setpoints associated with startup source breakers and the switchyard isolation circuitry. In a letter dated May 8, 1990 (ADAMS Accession No. ML16152A960), the licensee stated that on April 26, 1990, the licensee and NRC staff held a conference call during which NRC staff requested information about the modifications discussed in the LER to address the issue identified in the LERs. In its letter dated May 8, 1990, the licensee described a modification to install undervoltage relays on the 230-kV switchyard Yellow bus to monitor the switchyard voltage on the line side of each of the three startup transformers.

In its letter to the NRC dated June 18, 1990 (ADAMS Accession No. ML16152A977), the licensee stated that on June 6, 1990, a conference call was held between the licensee and NRC staff, presumably to continue discussions of the issues identified in LERs 90-04 and 90-05, during which the NRC staff raised a concern about the impact of degraded voltage on safety-related equipment during normal plant operation. In this letter, the licensee provided a discussion to address the concern, indicating that the existing undervoltage (loss of voltage) protection system on the feeders to the main buses that supply power to the safety-related buses was adequate for protection during normal power operation.

By letter to the licensee dated November 14, 1990 (ADAMS Accession Nos. ML16131A327 and ML16266A177), the NRC staff documented its review of the information that the licensee provided in its LERs and letters dated May 8, and June 18, 1990, and issued an SE that established NRC staff positions about the licensee's proposed modification to its degraded grid protection. As discussed in the cover letter dated November 14, 1990, the NRC staff concluded that the proposed modifications to the design would provide additional undervoltage protection and, in consideration of the complexity of the plant's existing undervoltage protection system and the onsite electrical distribution system, the proposed degraded grid protection modification was acceptable. In Section 3.0, "Evaluation," of the SE dated November 14, 1990, the staff stated that the guidance for the staff's review of the proposed modification is contained in Branch Technical Position (BTP) PSB-1, "Adequacy of Station Electrical Distribution System Voltages." In its SE, the staff described the licensee's proposed design by stating, "After a 9 second time delay this signal will then generate alarms in the control rooms and, if an ES [engineered safeguards] signal from any unit's Engineered Safeguards Protective System exists, will then isolate the 230 kV switchyard from the offsite 230 kV electrical grid." The staff also stated, "Also, the undervoltage condition in itself does not result in the separation of the Class 1E distribution system from the offsite grid; an ES (LOCA [loss of coolant accident], MSLB [main steam line break]) signal must exist coincidentally before undervoltage protection action occurs."

In Section 4.0, “Conclusion,” of the enclosed SE, the staff provided its position by stating:

> From the discussion above, it can be concluded that the licensee’s proposed modification does not fully meet BTP PSB-1 in several areas. Requirements similar to those contained in the BTP were generically applied to every plant (circa 1978). In the northeastern part of the country, low grid quality necessitated the staff to back away somewhat from the BTP requirements, particularly for the requirement to automatically separate the onsite Class 1E electrical distribution system from the degraded grid. For the northeast plants, the staff permitted the use of alarms, procedures and manual operator actions, in lieu of automatic action, to ensure that the safety-related components of the Class 1E systems would not be adversely affected during low voltage conditions. This compromise to the requirements of the BTP was granted due to the known weakness of the New England grid whereby the forced shutdown of one nuclear plant could lead to shutdown of other plants in a cascading manner.
>
> For Oconee, the proposed modification will add another layer of undervoltage protection to the existing, degraded grid protection circuitry. Due to the complexity of the plant’s existing undervoltage protection scheme and the onsite electrical distribution system coupled with the speculation that the quality of the grid servicing the Oconee site may have similar weaknesses to what exists in the Northeast, we conclude that it is not prudent to impose the complete requirements of the BTP. Therefore, we find that the licensee’s proposed degraded grid protection modification (excluding [TS] changes which will be evaluated in a separate SE) is acceptable.

3.4 Licensing Actions

The staff reviewed the following license amendments pertaining to degraded and loss of voltage protection. Some of these license amendments involved changes to the TS Bases. Prior to the removal of the TS Bases from the Oconee TSs via implementation of a license condition added per Amendments 300, 300, and 300 (i.e., the conversion of the Oconee TSs to the improved TSs (ITSs)), Oconee’s TS Bases were part of the TSs (i.e., Appendix A to the operating licenses) and, thus, were issued by the NRC via license amendments to the TSs.

3.4.1 Amendment Nos. 117, 117, and 114

On November 22, 1982, the NRC issued Amendment Nos. 117, 117, and 114 (ADAMS Accession No. ML012140380), which incorporated EPSL requirements in the TSs. In its application dated April 30, 1982 (ADAMS Accession Nos. ML15223A797 and ML15223A801), the licensee stated, “This report concerns an incident on Oconee Unit 3 in which portions of the EPSL were inadvertently made inoperable during maintenance. Duke considers that this incident may have been averted had the [TSs] contained an LCO on the EPSL circuitry, and thus requests that the proposed LCO be approved.” TS LCO 3.7.1(c) was added, which stated that the reactor shall not be heated above 200 degrees Fahrenheit unless the EPSL circuitry is operable as specified by the conditions of Table 3.7-1 for normal operation. TS LCO 3.7.2(b) was added, which stated the provisions of 3.7.1 may be modified to allow the circuits or channels of any single functional unit of the EPSL to be inoperable for test or maintenance for periods not exceeding 24 hours if the conditions of Table 3.7-1 for degraded operation or normal operation are satisfied. Table 3.7-1 of the TS Bases described how many operable circuits or channels were required during normal operation per TS 3.7.1(c) and degraded operation per

TS 3.7.2(b) for each of the 10 EPSL functional units. The TS Bases issued with the TSs stated, in part, "The [EPSL] in conjunction with its associated circuits, is designed with sufficient redundancy to assure that power is supplied to the unit Main Feeder Buses and, hence, to the unit's essential loads, under accident conditions. The logic system monitors the normal and emergency power sources and, upon loss of the normal power source (the UAT), the logic will seek an alternate source of power."

3.4.2 Amendment Nos. 127, 127, and 124

On March 2, 1984, the NRC issued Amendment Nos. 127, 127, and 124 (ADAMS Accession No. ML012180205). These amendments revised the TSs to implement LCOs in the event one startup transformer is out of service. The issue discussed in the NRC's letter to the licensee dated March 21, 1983 (ADAMS Accession Nos. ML15238A768 and ML15238A771), namely the distribution of voltages at the safety buses when one unit startup transformer is shared between two units, was considered closed with the issuance of these amendments. In the staff's SE for the amendments, the staff provided its position by stating:

> The NRC staff previously reviewed and found acceptable the Adequacy of Station Electric Distribution System Voltages for Oconee Nuclear Station, Units Nos. 1, 2 and 3. The staff's [SE] and associated Technical Evaluation Report were transmitted to Duke Power Company (DPC or the licensee) via [correspondence] dated March 21, 1983. The voltage analysis submitted by DPC as part of the documentation to be reviewed by the staff indicated that when a unit startup transformer is shared between two or more generating units, the distribution voltages at the safety buses become unacceptable. DPC agreed to implement [TS] changes which would prohibit the connection of more than one generating unit's load to a single startup transformer…. The above proposed TS changes, when implemented, will assure adequate distribution of voltages at the Class 1E buses in the event of loss of a startup transformer. We, therefore, find the proposed TS changes acceptable.

3.4.3 Amendment Nos. 232, 232, and 231

On September 4, 1998 (ADAMS Accession No. ML15261A466), NRC issued Amendments 232, 232, and 231, which completely revised the electrical distribution system section of the TSs. The TS Bases were also amended because they were part of the licensee's TSs prior to the licensee's ITS conversion. These amendments approved TSs related to degraded and loss of voltage protection.

TSs and TS Bases Changes

The amendments revised Section 3.7.1, "AC Sources – Operating." The TS Bases for TS 3.7.1 that were issued with the amendments stated, "Either of the following combinations provide an acceptable overhead emergency power path…. The 230 kV switchyard yellow bus capable of being isolated by one channel of Switchyard Isolate from Degraded Grid Voltage Protection circuitry…." Required Action I for the condition of when one or more required offsite sources are inoperable for reasons other than those in Conditions A or B requires the licensee to take actions, including verifying the operability of EPSL in one hour and to restore offsite sources to

operable status in 24 hours. The TS Bases (B 3.7-12) for Required Action I in TS 3.7.1 describe the required actions for degraded voltage conditions and state:

> With all of the required offsite sources inoperable due to degraded grid, loss of voltage, or other causes, sufficient standby AC power sources are available to maintain the unit in a safe shutdown condition in the event of a [design basis accident]. However, since the AC power system is degraded below the TS requirements, a time limit on continued operation is imposed. With only one of the required offsite sources OPERABLE, the likelihood of [loss of offsite power] is increased such that the same Required Actions for all required offsite sources inoperable are conservatively followed. The risk associated with continued operation for one hour without a Lee gas turbine energizing the standby buses is considered acceptable due to the low likelihood of a failure of both emergency power paths during this time period, and because of the potential for grid instability caused by the simultaneous shutdown of all three units. Operation with the available offsite sources less than required by the TS is permitted for 24 hours provided that the actions detailed below are taken prior to exceeding one hour. Further, with the exception of Lee energizing the standby buses, in the event these actions are not met during the inoperability of the required offsite sources, a period of 4 hours is allowed by Required Action I.3 to restore the inoperable component. For example if both required offsite sources have been inoperable 12 hours and one channel of load shed (required by TS 3.7.3) is discovered to be inoperable, the channel must be restored to OPERABLE status within the next 4 hours.

Surveillance Requirement (SR) 3.7.1.18 requires the licensee to verify each 230-kV switchyard breaker actuates to the correct position on an actual or simulated switchyard isolation actuation signal. The TS Bases for SR 3.7.1.18 state:

> This surveillance verifies proper operation of the 230 kV switchyard circuit breakers upon an actual or simulated actuation of the Switchyard Isolation circuitry. This test causes an actual switchyard isolation (by actuation of degraded grid voltage protection) and alignment of the [KHUs] to the overhead and underground emergency power paths. An 18 month frequency minimizes the impact to Keowee and the operating Units which are connected to the 230 kV switchyard. The effect of this surveillance is not significant because the generator red bus tie breakers and feeders from the Oconee 230 kV switchyard red bus to the system grid remain closed. Either Switchyard Isolation Channel causes full system realignment, which involves a complete switchyard realignment. To avoid excessive switchyard circuit breaker cycling, realignment and [KHU] emergency start functions, this surveillance need be performed for only one Switchyard Isolation Channel each surveillance interval. This is acceptable since operability of the overhead emergency power path requires only one channel of the Switchyard Isolation circuitry to be capable of isolating the switchyard. Functional verification of the Switchyard Isolation Channel logic is addressed in [TS] 3.7.6, "[EPSL] Degraded Grid Voltage Protection."

The amendments revised TS 3.7.2. The TS Bases for TS 3.7.2, "Distribution Systems – Operating," state in the background section that safety functions provided by the 230-kV switchyard 125-V direct current (DC) system include isolation of Oconee (including Keowee) from degraded grid voltage through action of the Degraded Grid Protection System (DGPS).

The TS Bases state in the applicable safety analyses section that for an ES actuation concurrent with a loss or degradation of offsite AC power, assuming a worst case single failure, the 230-kV DC switchyard Distribution System provides power to components and protective systems which function to maintain OPERABLE at least one of the onsite power sources, and separate Oconee and the onsite power sources from the electrical system grid, should grid voltage be lost or degraded.

The amendments added TS 3.7.4, "[EPSL] Voltage Sensing Circuits," which are the TSs for loss-of-voltage protection. The amendments also added SR 3.7.4.1, which required the licensee to perform a channel test every 18 months. No setpoints were provided within the channel test requirement. The TS Bases (B 3.7-39) for TS 3.7.4 in the background section state:

> The [EPSL] Voltage Sensing Circuits consist of the voltage sensing circuits for the Startup Source, Standby Bus #1, Standby Bus #2, and the Normal Source. These voltage sensing circuits provide input to the EPSL power seeking logic to actuate breakers and initiate transfer logic sequences. Each phase of each source has an individual potential transformer feeding a 2 out of 3 logic for determining the status of the power source. The voltage sensing circuits also provide class 1E trip signals to the breaker control circuitry for the N, E, and SL breakers.

The TS Bases (B 3.7-41) for SR 3.7.4.1 state:

> This surveillance verifies operability of each sensing circuit of each bus which can supply the MFBs. A circuit is defined as three channels, one for each phase. Each channel consists of all components from the sensing power transformer on the actual buswork through the circuit auxiliary relays which operate contacts in the EPSL logic and breaker trip circuits. Actual setpoint values for the undervoltage relays on the N and E breakers are verified independently as a prerequisite to this SR. Minimum requirements consist of individual channel relay operation causing appropriate contact responses within associated loadshed/breaker circuits, alarm activations, and proper indications for the sensing circuit control power status. The frequency for this SR is reasonable based on operating experience and the need to remove the bus from service to perform required testing.

The amendments added TS 3.7.6, "[EPSL] Degraded Grid Voltage Protection," which included LCO 3.7.6, which stated that the following EPSL Degraded Grid Voltage Protection functions shall be OPERABLE: three switchyard degraded grid voltage sensing relays and two channels of switchyard degraded grid voltage protection actuation logic. This TS also included required actions and SRs (i.e., a channel calibration and a channel test). The TS Bases (B 3.7-45) for TS 3.7.6 state in the background section:

> Two independent levels of protection are provided to assure the degradation of voltage from offsite sources does not adversely impact the function of safety-related systems and components. The first level of protection is provided by the EPSL [DGPS]. The second level of protection is provided by undervoltage relaying on the E and N breakers (reference TS 3.7.4, EPSL Voltage Sensing Circuits) which protects from loss of voltage.

> The DGPS, upon indication of inadequate voltage, will provide an alarm to the Unit 1 & 2 Control room and the Spartanburg Dispatcher. If any single [ES] Channel 1 or 2 signal from any Unit is sensed by the DGPS, while the voltage is below acceptable levels, the DGPS will initiate an isolation of the 230kV switchyard Yellow Bus to ensure the onsite overhead emergency power path is available. Each DGPS actuation logic channel is capable of isolating the overhead emergency power path by a set of 94V relays and the associated switchyard PCB [power circuit breaker] trip coil. The sets of actuating (94V) relays are common to the DGPS and the undervoltage part of another system called the External Grid Trouble Protection System (EGTPS). The isolation of the yellow bus is accomplished by opening switchyard PCBs 8, 12, 15, 17, 21, 24, 26, 28, and 33. While the DGPS relaying could result in the unavailability of the overhead emergency power path, it does ensure that the startup transformers are not connected to a degraded source of power. In this event, ES loads are provided adequate voltage from the standby buses. The EGTPS serves to protect from grid collapse.
>
> Based on historical data, it is anticipated any degradation of the voltage in the 230kV switchyard will not last for an extended period of time. Administrative procedures are in place to assure timely actions are taken to restore the voltage.
>
> There are three undervoltage relays installed to monitor the switchyard voltage, one on each of the yellow bus phases. Each of the undervoltage relays is supplied by a single phase coupling-capacitor voltage transformer. The undervoltage relay contacts are arranged in a 2-out-of-3 logic sequence which feeds two redundant time delay (drop) relays. The time delay relays were added to prevent spurious actuations, but still provide adequate response time to voltage transients. Either of the two redundant time-delay relays will cause either of the two sets of actuating relays to initiate switchyard isolation. The DGPS voltage sensing may be considered OPERABLE when in a tripped condition. Circuit control power is fed from the 230kV Switchyard 125VDC system.
>
> The purpose of the DGPS is to ensure adequate voltage is available during an ES actuation concurrent with a 230kV switchyard voltage of less than 226kV.

These amendments also added TS 3.7.7, "[EPSL] CT-5 Degraded Grid Voltage Protection," which included LCO 3.7.7, which stated that the following EPSL CT-5 Degraded Grid Voltage Protection functions shall be OPERABLE: three CT-5 Degraded Grid Voltage Sensing Relays, and two channels of CT-5 Degraded Grid Voltage Protection Actuation Logic. This TS also included required actions and SRs (i.e., a channel calibration and a channel test). TS Bases were also issued with the amendments which described the bases for the TS changes.

Safety Evaluation for AMDs 232, 232, and 231

Section 3.0, "Emergency Electrical System Design Description," of the NRC staff's SE for these amendments describes the staff's understanding of the licensee's degraded voltage protection design. In Section 3.0 of the SE, the staff provided its position by stating:

> Each Keowee unit is provided with its own automatic startup equipment. On an [EGTPS] actuation, an [ES] actuation, or a MFB monitor undervoltage actuation, both units start automatically and simultaneously, and run on standby. The

> output breaker closes on unit designated to supply the underground feeder and the other unit is available to supply the ONS [Oconee Nuclear Station] 230 kv switching station, if needed. If there is a system disturbance, this unit is connected automatically to the Oconee 230 kv yellow bus only after the Oconee 230 kv yellow bus is isolated automatically from the system and a preset time delay has elapsed. An [EGTPS] is designed to isolate the 230 kv yellow bus upon failure of the external transmission network. A [DGPS] monitors the 230 kv yellow bus for degraded voltage conditions. By design, actuation of this system and the presence of an engineered safeguard signal also results in isolating the 230 kv yellow bus. Thus, on separation from the external transmission network, both of the [KHUs] provide emergency power to the ONS units by way of either the 230 kv switching station and a unit's respective startup transformer or the underground feeder, transformer CT-4, and the standby buses.

Section 4.5, "TS 3.7.4, '[EPSL] Voltage Sensing Circuits,'" of the NRC staff's SE describes the staff's basis for approving the TSs for the second level of undervoltage relaying on the E and N breakers, which protect from a loss of voltage. In the SE, the staff provided its position by stating:

> Proposed TS Section 3.7.3 addresses three of the eight EPSL functional units contained in the current TS, and proposed TS Section 3.7.4 addresses an additional three. The three addressed by proposed TS Section 3.7.4 are normal source voltage sensing circuits (one per phase), startup source voltage sensing circuits (one per phase), and standby bus voltage sensing circuits (one per phase on each bus). With the exception of the issue relating to multiple simultaneous degradation of EPSL functional units, which is addressed above for proposed TS Section 3.7.3, proposed TS Section 3.7.4 contains requirements that are consistent with those in the current TS.
>
> 4.5.4 Proposed Surveillance Requirement
>
> Proposed TS Section 3.7.4 contains one SR. SR 3.7.4.1 requires performing a channel test on an 18-month frequency. The current TS do not require a surveillance for the normal source voltage sensing circuits. Thus, this is an additional requirement that is not included in the current TS. In addition, SR 3.7.4.1 verifies operability of each sensing circuit of each bus, which can supply the MFBs. A circuit is defined as three channels, one for each phase. Each channel consists of all components from the sensing power transformer on the actual buswork through the circuit auxiliary relays that operate contacts in the EPSL logic and breaker trip circuits. Actual setpoint values for the undervoltage relays for the N and E breakers are to be verified independently as a prerequisite to this SR. Minimum requirements consist of individual channel relay operation causing appropriate contact responses within associated loadshed/breaker circuits, alarm activations, and proper indications for the sensing circuit control power status. The 18-month frequency for this SR considers operating experience and the need to remove the bus from service to perform the required testing.

Section 4.7, "TS 3.7.6, '[EPSL] Degraded Grid Voltage Protection,'" of the NRC staff's SE describes the staff's basis for approving the TSs for degraded voltage protection.
In Section 4.7.1, "Background," of the SE, the staff provided its position by stating:

> Two independent levels of protection are provided to assure the degradation of voltage from offsite sources does not adversely impact the function of safety-related systems and components. The first level of protection is provided by the EPSL [DGPS]. The second level of protection is provided by undervoltage relaying on the E and N breakers (addressed in proposed TS Section 3.7.4), which protects from loss of voltage. Upon indication of inadequate voltage, the DGPS is designed to provide an alarm to the Unit 1 and Unit 2 control room and the Spartanburg dispatcher. If any single [ES] Channel 1 or 2 signal from any unit is sensed by the DGPS while the voltage is below acceptable levels, the DGPS is designed to initiate an isolation of the 230 kV switchyard yellow bus to ensure that the onsite overhead emergency power path is available.
>
> Each DGPS actuation logic channel is capable of isolating the overhead emergency power path by a set of actuating relays and the associated switchyard [PCB] trip coils. The sets of actuating relays are common to the DGPS and the undervoltage part of another system called the [EGTPS]. Isolation of the 230 kV switchyard yellow bus is accomplished by opening nine switchyard PCBs.
>
> There are three undervoltage relays installed to monitor the switchyard voltage, one for each phase of the 230 kV yellow bus. Each of the undervoltage relays is supplied by a single phase coupling-capacitor voltage transformer. The undervoltage relay contacts are arranged in a two out of three logic configuration that feeds two redundant time delay dropout relays. The time delay relays are provided to prevent spurious actuations, as well as providing adequate response time to voltage transients. Either of the two redundant time delay relays is designed to cause either of the two sets of actuating relays to initiate switchyard isolation. A DGPS voltage sensing relay may be considered operable when it is in a tripped condition since this reduces the logic from a two out of three function to a one out of two function, which is conservative with regard to actuation. The two sets of actuating relays are shared with the voltage channels of the EGTPS and the associated switchyard.

Amendment Nos. 300, 300, and 300

Oconee transitioned to the ITS via Amendment Nos. 300, 300, and 300, which were issued on December 16, 1998 (ADAMS Accession Nos. ML012060036, ML15261A511, and ML15261A512). These amendments relocated the EPSL requirements from Section 3.7 to Section 3.3 of the TSs and renumbered TS 3.7 to 3.8 among other changes. Section G, "Evaluation of Beyond-Scope Items," of the NRC staff's SE for requested changes that were beyond the scope of NUREG-1430, states:

> I. Amendments Approved During the ITS Review
>
> During the review of the ITS amendment application, the following amendments were approved, issued, and implemented. To ensure none were lost in the

conversion process, the licensee ensured that each had been addressed in the ITS amendment. …

j. Emergency Electrical System, Amendment Nos. 232, 232, 231 (Units 1, 2, and 3, respectively), issued September 4, 1998 [ADAMS Accession No. ML15261A466].

4.0 NRR RESPONSE TO THE TIA REQUEST

NRC Region II staff requested NRR to answer the following question:

> Are the situations discussed in the TIA Background section, under Issues 1, 2, and 3, consistent with the Oconee licensing basis and applicable staff positions for Oconee? Issues 1, 2, and 3 are summarized as follows:
>
> 1. DVRs are not installed on the 4.16-kV safety buses during normal operation when those buses are fed from the UATs.
> 2. The licensee uses manual actions during mitigation of degraded voltage conditions.
> 3. LOP relay setpoints and time delays are not in the TSs.

NRR Response

Yes, the subject situations are consistent with the Oconee licensing basis and applicable staff positions for Oconee. Individual responses to each issue follow.

Issue 1:

In its TIA request of November 7, 2014, NRC Region II described its concern that the DVR configuration (second level undervoltage protection) at Oconee was not located on the Class 1E 4.16-kV safety buses, and that the 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 KHUs to meet the UFSAR 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 switchyard is energizing the standby buses in operation modes 1 through 4. As a result of the DVR configuration being located on the 230-kV switchyard Yellow bus and on Transformer 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 UATs. Region II described the NRC and licensee correspondence regarding the NRC letter dated June 3, 1977, and LERs 269/90-04 and 90-05. Region II then described its concern that the DVR configuration would result in a lack of second level undervoltage protection for the ES because the configuration was not located at the 4.16-kV safety buses and, therefore, was not in conformance with the Oconee General Design Criterion 39, as described in Section 3.1.39 of the UFSAR.

NRR Response to Issue 1

Based on NRR staff's review of the NRC staff positions in docketed correspondence, the licensing basis established in issued amendments, and the UFSAR, as discussed in Section 2 of this assessment, the NRR staff concludes that the lack of DVRs on the 4.16-kV safety buses

during normal operation when those buses are fed from the UATs is consistent with Oconee's licensing basis and NRC staff positions as applied to Oconee regarding degraded voltage protection.

In its letter dated May 8, 1990 (ADAMS Accession No. ML16152A960), the licensee described a modification to install undervoltage relays *on the 230-kV switchyard Yellow bus* to monitor the switchyard voltage on the line side of each of the three startup transformers. By letter to the licensee dated November 14, 1990 (ADAMS Accession Nos. ML16131A327 and ML16266A177), the NRC staff documented its review of the information that the licensee provided in its LERs and letters dated May 8, and June 18, 1990, and issued an SE that established NRC staff positions about the licensee's proposed modification to its degraded grid protection. As discussed in the cover letter dated November 14, 1990, the NRC staff concluded that the proposed modifications to the design would provide additional undervoltage protection and, in consideration of the complexity of the plant's existing undervoltage protection system and the onsite electrical distribution system, the proposed degraded grid protection modification was acceptable. In Section 3.0, "Evaluation," of the enclosed SE, the staff stated that the guidance for the staff's review of the proposed modification is contained in BTP PSB-1. In Section 4.0, "Conclusion," of the enclosed SE, the staff stated:

> Due to the complexity of the plant's existing undervoltage protection scheme and the onsite electrical distribution system coupled with the speculation that the quality of the grid servicing the Oconee site may have similar weaknesses to what exists in the Northeast, we conclude that it is not prudent to impose the complete requirements of the BTP. *Therefore, we find that the licensee's proposed degraded grid protection modification (excluding [TS] changes which will be evaluated in a separate SE) is acceptable [emphasis added].*

The DVR configuration being located on the 230-kV switchyard Yellow bus and on Transformer CT-5 when the Central 100-kV switchyard is energizing the standby buses in MODES 1 through 4 is consistent with TSs issued in and supporting SE for Amendments 232, 232, and 231 issued to Oconee on September 4, 1998, and the subsequent ITS amendments. Amendments 232, 232, and 231 revised Section 3.7.1 of the TSs. The TS Bases for TS 3.7.1 that were issued with the amendments and as part of the TSs stated, "Either of the following combinations provide an acceptable overhead emergency power path…. The *230 kV switchyard yellow bus [emphasis added]* capable of being isolated by one channel of Switchyard Isolate from Degraded Grid Voltage Protection circuitry…." The staff notes that this statement does not refer to the 4.16-kV buses. SR 3.7.1.18 requires the licensee to verify each 230-kV switchyard breaker actuates to the correct position on an actual or simulated switchyard isolation actuation signal. The TS Bases for SR 3.7.1.18 state, "This surveillance verifies proper operation of the 230 kV switchyard circuit breakers upon an actual or simulated actuation of the Switchyard Isolation circuitry. This test causes an actual switchyard isolation (by actuation of degraded grid voltage protection)…." The amendments added TS 3.7.6, "[EPSL] Degraded Grid Voltage Protection," which included LCO 3.7.6, which stated that the following EPSL Degraded Grid Voltage Protection functions shall be OPERABLE: three switchyard degraded grid voltage sensing relays and two channels of switchyard degraded grid voltage protection actuation logic. The TS Bases for TS 3.7.6 state in the background section, "There are three undervoltage relays installed to monitor the switchyard voltage, one on each of the yellow bus phases. … The purpose of the DGPS is to ensure adequate voltage is available during an ES actuation concurrent with a 230kV switchyard voltage of less than 226kV." These TSs and TS bases discuss the degraded voltage protection monitoring the 230-kV switchyard buses, not the 4.16-kV buses.

In the staff's SE for these amendments, the staff states, "A [DGPS] monitors the 230 kv yellow bus for degraded voltage conditions. By design, actuation of this system and the presence of an engineered safeguard signal also results in isolating the 230 kv yellow bus. … There are three undervoltage relays installed to monitor the switchyard voltage, one for each phase of the 230 kV yellow bus." These statements show that the staff understood the degraded voltage protection was for monitoring the voltage on the 230-kV yellow bus. In its SE for the ITS conversion (Amendments 300, 300, and 300), the staff stated that the licensee ensured that Amendment Nos. 232, 232, and 231 were addressed in the ITS amendment.

Based on the staff's review of licensing actions and correspondence between the NRC and licensee regarding the design of the degraded voltage protection system, the staff found that the NRC approved the licensee to have degraded voltage protection for the switchyard 230-kV yellow bus, rather than for the 4.16-kV safety buses during normal operation when those buses are fed from the UATs. Therefore, the staff found that the not having the degraded voltage protection on the 4.16-kV safety buses during normal operation when those buses are fed from the UATs is consistent with the licensing basis.

<u>Issue 2</u>:

In its TIA request of November 7, 2014, NRC Region II described its concern that 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 minutes for licensee operators to initiate separation from the grid upon a degraded condition. Region II then described its concern that the use of manual actions to mitigate a degraded voltage condition is contrary to Oconee Design Criterion 39 via the NRC letter dated June 3, 1977, 10 CFR 50, Appendix B, Criterion III, "Design Control," 10 CFR 50.55a(h)(2), "Protection Systems," and Regulatory Issue Summary 2011-12, "Adequacy of Station Electric Distribution System Voltages." Paragraph 50.55a(h)(2), "Protection systems," of 10 CFR states, "… For nuclear power plants with construction permits issued before January 1, 1971, protection systems must be consistent with their licensing basis or may meet the requirements of IEEE Std. 603–1991 and the correction sheet dated January 30, 1995.

<u>NRR Response to Issue 2</u>

Based on the NRR staff's review of NRC SEs and licensing actions, the staff finds that using manual actions to mitigate a degraded voltage condition on the 230-kV switchyard Yellow bus, without an ES signal, is consistent with the Oconee licensing basis. The NRC's SE dated November 14, 1990, acknowledged that a degraded grid condition in and of itself would not result in the separation of the Class 1E distribution system from the grid; rather, a coincident ES signal would have to be present with the degraded grid condition. In addition, the NRC staff's SE compared Oconee's grid to the New England grid, and the staff allowed the use of manual actions to mitigate low voltage conditions for plants in the Northeast because of grid weaknesses. The staff used this justification, in part, for finding Oconee's design acceptable even though it did not meet BTP PSB-1. In the SE, the NRC staff stated:

> After a 9 second time delay this signal will then generate alarms in the control rooms and, *if an ES signal from any unit's Engineered Safeguards Protective System exists [emphasis added]*, will then isolate the 230 kV switchyard from the

> offsite 230 kV electrical grid. … A second, longer time delay has not been incorporated into the design. *Also, the undervoltage condition in itself does not result in the separation of the Class 1E distribution system from the offsite grid; an ES (LOCA, MSLB) signal must exist coincidentally before undervoltage protection action occurs [emphasis added]*.
> …
> For the northeast plants, *the staff permitted the use of alarms, procedures and manual actions, in lieu of automatic action [emphasis added]*, to ensure that the safety-related components of the Class 1E systems would not be adversely affected during low voltage conditions. This compromise to the requirements of the BTP was granted due to the known weakness of the New England grid whereby the forced shutdown of one nuclear plant could lead to a shutdown of other plants in a cascading manner.
>
> For Oconee, the proposed modification will add another layer of undervoltage protection to the existing, degraded grid protection circuitry. *Due to the complexity of the plant's existing undervoltage protection scheme and the onsite electrical distribution system coupled with the speculation that the quality of the grid servicing the Oconee site may have similar weaknesses to what exists in the Northeast, we conclude that it is not prudent to impose the complete requirements of the BTP [emphasis added]*. Therefore, we find that the licensee's proposed degraded grid protection modification (excluding [TS] changes which will be evaluated in a separate SE) is acceptable.

In addition, the TS Bases issued as part of Amendments 232, 232, and 231 state that based on historical data, it is anticipated any degradation of the voltage in the 230-kV switchyard will not last for an extended period of time and that administrative procedures are in place to assure timely actions are taken to restore the voltage. The TS Bases for TS 3.7.6 state in the background section:

> The DGPS, upon indication of inadequate voltage, will provide an alarm to the Unit 1 & 2 Control room and the Spartanburg Dispatcher. If any single [ES] Channel 1 or 2 signal from any Unit is sensed by the DGPS, while the voltage is below acceptable levels, the DGPS will initiate an isolation of the 230kV switchyard Yellow Bus to ensure the onsite overhead emergency power path is available. … Based on historical data, it is anticipated any degradation of the voltage in the 230kV switchyard will not last for an extended period of time. Administrative procedures are in place to assure timely actions are taken to restore the voltage.

The TS Bases and NRC's SE associated with Amendments 232, 232, and 231 state that if an ES signal is present concurrent with a degraded grid condition, then automatic actions will be used to mitigate that scenario. The amendments did not require automatic actions for a sustained degraded voltage condition without an ES signal present. Amendments 232, 232, and 231 revised TS 3.7.2. The TS Bases for TS 3.7.2, "Distribution Systems – Operating," state that for an ES actuation concurrent with a loss or degradation of offsite AC power, assuming a worst case single failure, the 230-kV DC Switchyard Distribution System provides power to components and protective systems which function to maintain OPERABLE at least one of the onsite power sources, and separate Oconee and the onsite power sources from the electrical system grid, should grid voltage be lost or degraded. Section 3.0, "Emergency Electrical System Design Description," of the NRC staff's SE for these amendments describes the staff's

understanding of the licensee's degraded voltage protection design and states: "By design, actuation of this system and the presence of an engineered safeguard signal also results in isolating the 230 kv yellow bus." Section 4.7, "TS 3.7.6, '[EPSL] Degraded Grid Voltage Protection,'" of the NRC staff's SE describes the staff's basis for approving the TSs for degraded voltage protection. Section 4.7.1, "Background," of the SE states:

> Upon indication of inadequate voltage, the DGPS is designed to provide an alarm to the Unit 1 and Unit 2 control room and the Spartanburg dispatcher. If any single [ES] Channel 1 or 2 signal from any unit is sensed by the DGPS while the voltage is below acceptable levels, the DGPS is designed to initiate an isolation of the 230 kV switchyard yellow bus to ensure that the onsite overhead emergency power path is available.

Condition/Required Action I in TS 3.7.1 in Amendments 232, 232, and 231 (currently Condition/Required Action J after the ITS conversion) also provided an allowed outage time for restoring degraded grid conditions. For the condition of when one or more required offsite sources are inoperable for reasons other than those in Conditions A or B, Required Action I requires the licensee to take actions, including verifying the operability of EPSL in one hour and to restore offsite sources to operable status in 24 hours. The TS Bases for Required Action I in TS 3.7.1 describe the required actions for degraded voltage conditions and state:

> With all of the required offsite sources inoperable due to degraded grid, loss of voltage, or other causes, sufficient standby AC power sources are available to maintain the unit in a safe shutdown condition in the event of a [design basis accident]. However, since the AC power system is degraded below the TS requirements, a time limit on continued operation is imposed. With only one of the required offsite sources OPERABLE, the likelihood of [loss of offsite power] is increased such that the same Required Actions for all required offsite sources inoperable are conservatively followed. The risk associated with continued operation for one hour without a Lee gas turbine energizing the standby buses is considered acceptable due to the low likelihood of a failure of both emergency power paths during this time period, and because of the potential for grid instability caused by the simultaneous shutdown of all three units. Operation with the available offsite sources less than required by the TS is permitted for 24 hours provided that the actions detailed below are taken prior to exceeding one hour. Further, with the exception of Lee energizing the standby buses, in the event these actions are not met during the inoperability of the required offsite sources, a period of 4 hours is allowed by Required Action I.3 to restore the inoperable component. For example if both required offsite sources have been inoperable 12 hours and one channel of load shed (required by TS 3.7.3) is discovered to be inoperable, the channel must be restored to OPERABLE status within the next 4 hours.

Section 8.2.1.3.1 of the UFSAR states, "*If an ESF [engineered safeguards] signal is sensed [emphasis added]* by the degraded grid protection system, while the voltage is sustained below acceptable levels, the degraded grid protection system will initiate an isolation of the 230-kV switchyard (i.e., of the yellow bus) and start the KHUs so that the onsite emergency overhead power path is available." Section 8.2.1.3.1 of the UFSAR states that it is anticipated that any degradation of the voltage in the 230-kV switchyard will not last for an extended period of time, that it is recognized that the voltage in the switchyard needs to be maintained above acceptable

levels, *and that corrective measures would be taken to assure that timely actions are taken to restore the voltage [emphasis added]*.

Based on the licensing actions and correspondence, the NRR staff concludes that the NRC required automatic actions for a degraded grid condition if an ES signal is present. For degraded voltage conditions without an ES signal, the licensing actions and correspondence indicate that manual actions are acceptable (e.g., "administrative procedures are in place to assure timely actions are taken to restore the voltage," and issuing TSs that allow a completion time to restore degraded voltage).

Regarding the concern that the use of manual actions to mitigate a degraded voltage condition is contrary to Oconee Design Criterion 39, 10 CFR 50, Appendix B, Criterion III, 10 CFR 50.55a(h)(2), and Regulatory Issue Summary 2011-12, the NRR staff finds that the use of manual actions to mitigate a degraded voltage condition without an ES signal present is consistent with Oconee's licensing basis as described above. Additionally, generic communications, such as Regulatory Issue Summaries, do not constitute requirements.

<u>Issue 3</u>:

In its TIA request of November 7, 2014, NRC Region II described its concern that although the licensee credits operation of the LOP relays (first level undervoltage protection) for monitoring the 4.16 kV MFBs to disconnect from offsite power on a loss of voltage condition, and subsequently re-connect to the KHUs to meet the Chapter 15 plant accident analyses, the LOP relay setpoints and associated time delays are not included in the plant TSs. Region II then described a comparison of the Oconee TSs to the Babcock and Wilcox Standard Technical Specifications (STSs) in NUREG-1430. The Region also stated its concern that the Oconee TSs do not meet 10 CFR 50.36(c)(2)(ii)(C), "Criterion 3."

<u>NRR Response to Issue 3</u>

Based on the NRR staff's review of Amendments 232, 232, and 231, the staff approved the TS SR for the LOP relays that did not include the voltage and time delay setpoint values. The amendments added TS 3.7.4, which are the TSs for loss-of-voltage protection. The amendments also added SR 3.7.4.1, which required the licensee to perform a channel test every 18 months. No setpoint values were provided within the channel test requirement. As stated in its SE and in the TS Bases issued as part of the TSs, "Actual setpoint values for the undervoltage relays for the N and E breakers are to be verified independently as a prerequisite to this SR." However, this statement was not included in the TSs or TS Bases issued as part of the ITS conversion (Amendment Nos. 300, 300, and 300). TS 3.7.4 was moved to TS 3.3.18 as part of the ITS conversion. ITS SR 3.3.18.1 states, "Perform CHANNEL FUNCTION TEST," at a frequency of 18 months. The ITS Bases for SR 3.3.18.1 issued in Amendments 300, 300, and 300 states:

> A CHANNEL FUNCTIONAL TEST is performed on each voltage sensing circuit channel to ensure the channel will perform its function. A circuit is defined as three channels, one for each phase. Each channel consists of components from the sensing power transformer through the circuit auxiliary relays which operate contacts in the EPSL logic and breaker trip circuits. Minimum requirements consist of individual channel relay operation causing appropriate contact responses within associated loadshed/breaker circuits, alarm activations, and proper indications for the sensing circuit control power status. The Frequency of

> 18 months is based on engineering judgment and operating experience that determined testing on an 18 month interval provides reasonable assurance that the circuitry is available to perform its safety function.

Based on this description in the TS Bases, the NRR staff concludes that the TS and TS Bases did not retain the requirements to independently verify actual setpoint values for the undervoltage relays for the N and E breakers as a prerequisite to the SR.

Regarding the concern that the TSs do not meet 10 CFR 50.36(c)(2)(ii)(C), “Criterion 3,” Section 50.36(c)(2)(iii) states that a licensee is not required to propose to modify TSs that are included in any license issued before August 18, 1995, to satisfy the criteria in paragraph (c)(2)(ii) of this section. The Atomic Energy Commission issued the operating licenses for Oconee Units 1, 2, and 3 on February 6, 1973, October 6, 1973, and July 19, 1974, respectively. Therefore, the licensee was not required to proposed to modify TSs to satisfy 10 CFR 50.36(c)(2)(iii). In addition, the STSs in NUREG-1430 do not constitute requirements.

5.0 CONCLUSION

The NRR staff concludes that the situations presented in Issues 1, 2, and 3 of TIA 2014-04 are consistent with Oconee’s licensing basis and pertinent staff positions applicable to Oconee. The NRR staff’s conclusion is based solely on its review of the documents described in this evaluation. This TIA response is specific to Oconee. Although Issues 1, 2, and 3 of TIA 2014-04, as revised, are consistent with Oconee’s licensing basis and pertinent staff positions applicable to Oconee, concerns associated with the Oconee licensing basis that involve new or changed regulatory requirements or new staff positions regarding regulatory requirements should be addressed in accordance with the NRC’s backfitting requirements and supporting guidance.