SERC RELIABILITY CORPORATION

2019 Fall Compliance Seminar

This document provides SERC staff responses to questions asked by entities. The information provided herein is intended, on its date of posting, to provide guidance to the industry. Actions based on this information shall have no standing for the purpose of contesting or mitigating any findings of noncompliance by SERC. Compliance depends on a number of factors including the precise language of the Standard, the specific facts and circumstances, and the quality of evidence. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time.

1. TPL-007-3 R12 states:

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R12.

Additionally, the Technical Guidelines state the following:

Requirement R12
Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada.
- Research institutions and academic universities;
- Entities with installed magnetometers.

Further, the Rationale provided in the standard states:

The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments. Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities;
- Installed magnetometers; and
- Commercial or third-party sources of geomagnetic field data.

Geomagnetic field data for a Planning Coordinator's planning area is obtained from one or more of the above data sources located in the Planning Coordinator's planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator's planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area.

Questions:

1) The requirement only requires that a process be in place obtain geomagnetic field data for its Planning Coordinator area. The Technical Rationale makes it clear that the magnetometer does not have to be physically located within the PC area. The Technical Guidelines do provide the statement that it should be from the nearest accessible magnetometer.

   a. Is it expected that the PC "prove" they are getting the data from the nearest magnetometer? Or is acceptable to simply select the nearest U.S. Geological Survey?

   b. Can you provide an example of what data is expected?

   c. Is there expected frequency for gathering the data? It is presumed that the data will be used in performing assessments. Is it acceptable for the process to simply indicate that the data will be obtained periodically from the nearest U.S. Geological Survey prior to make a determination regarding model validation?

RESPONSE:

a. No. The objective is for entities to demonstrate that they have a process to obtain geomagnetic field data to validate models. It is not necessary to get it from the nearest magnetometer. See TPL-007-3 – Supplemental Material Page 38 of 44

b. Electronic or hard copies of its process to obtain geomagnetic field data and the data obtained for its Planning Coordinator's planning area.

c. At least once every 60 calendar months. The data should be used to inform the GMD Vulnerability Assessments.

2. Standard: PRC-023-4

Requirement 6 in the PRC-023-4 Standard states the following:

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall:

- **6.1** Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

- **6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its

Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

Questions:

a. Following an assessment an entity may have additions or deletions to the list. If an entity does have an addition or deletion the entity is required to provide the ERO with the update within 30 days of the change. Where should that change be submitted? Note: It is recognized that the ERO does have an annual data submittal but that could be outside the 30 day window so it would appear that the entity would need to have an alternative means to submit.

b. If an improvement is made that allows the element to be removed from the list does the 30 day notification to the ERO, RC, and TOs, GOs, DPs begin at the time of the improvement being commissioned into service or 30 days after the next assessment is done to confirm that it can be removed? It would seem appropriate to wait until the assessment period to assure that other issues haven't arisen that would negate it being removed.

Under review. Response to be posted upon receipt.

3. PRC-006-3

R1 of PRC-006-3 Requires that "Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. "

R2 requires: "Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program…"

R3 Requires: "Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets": Specified criteria.

R4 Requires: "Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2."

Questions

a. With respect to Requirement 2, is there any expected periodicity for identifying the islands that require study? Absence any verbiage requiring a specified periodicity, would an Entity be found compliant if they identified islands, for example every 10 years, if their criteria document permitted that interval?

b. R4 requires that an UFLS design assessment be done at least every five (5) years on islands that have been identified pursuant to Requirement 2. However there is not an explicit periodicity stated to identify the islands in requirement 2. Once a new island is identified, how long does an entity have to conduct and document the initial UFLS design assessment pursuant to R4?

RESPONSE:

a. A UFLS design assessment must be performed at least once every five years.

b. Per R12, if the island reconfiguration is event-driven, then two years Per R15.

4. Last year my Low Impact site completed the CIP self-certification. I didn't receive any feedback after submitting all of my evidence, so I'm wondering if we should expect a full CIP audit in 2020 or 2021 with the implementation of CIP-003 v7?

RESPONSE: We need to know the name of the entity; so we can find out why a letter was not sent. You would have already been notified if you are scheduled for an audit in 2020.

5. If Low Impact sites are going to be audited, will we be expected to use the CIP evidence tool, or will we just submit our evidence like we did for the self-certification?

Under review. Response to be posted upon receipt.

6. PRC-025 Generator Relay Loadability Question / Calculations related to Option 15a High side GSU minimum relay pickup current for instantaneous overcurrent (50) and timed overcurrent (51)

In NERC Reliability Standard PRC-025-2, Equation 158 on PDF page 104 of the Standard for reactive power is based on 120% of the rated real power in MW based where rated real power is determined from the generators rated MVA power at rated power factor. This approach does not seem appropriate as this calculation for reactive power to be use in equation 158 will result in a reactive power value far above the generator MVA capability at rated real power and associated reactive power. Following equation 158 approach for determining MVA at rated power factor and will likely yield minimum pickup currents for the 50 and 51 relays higher than may actually be intended by the PRC-025-2 Standard and can result in minimum pickup currents that may damage BES Elements if implemented in protection relaying to meet compliance with the PRC-025-2 Standard.

It seems the Q value for Equation 158 should be based on 120% of the rated reactive power that can be achieved at the rated power factor for the generator at 100% generator nameplate MVA.

Further, option 15a is applicable to the relaying associated with the high side of the generator step-up (GSU) transformer, however, the calculations are based on the ratings of the generation associated with the GSU. This approach assumes the GSU is not the limiting Element in the electrical path from the generator to transmission interconnection point. If the GSU is the limiting Element, then determining overcurrent relay settings based on the associated generator may result in relay settings that could damage the GSU under fault conditions.

Please respond to the following questions:

a. What is the engineering rationale for Equation 158 as it is in the PRC-025-2 Standard for Q based on 120% rated generator power P when the result of Q far exceeds what the generator will produce at rated P?

b. What is the engineering rationale for setting the GSU relaying based on the ratings of another Element, in this case, the generator?

c. If it is determined the engineering rationale for equation 158 is sound, however, upon application of equation 158 by an operating entity it is determined the minimum relay pick-up current determined using equation 158 will exceed the thermal damage curve of the applicable transformer, is the entity required to move to these settings even though it may cause damage to the transformer under a fault condition?

d. Would NERC accept a compliance position by an operating entity under NERC audit taking exception to the criteria stipulated by PRC-025-2 if the outcomes result in relay settings that could result in equipment damage under fault conditions and provide a defense explaining why applicable relay settings are unable to meet criteria stipulated under PRC-025-2 and the basis for such position and circumstances in the PRC-025 RSAW?

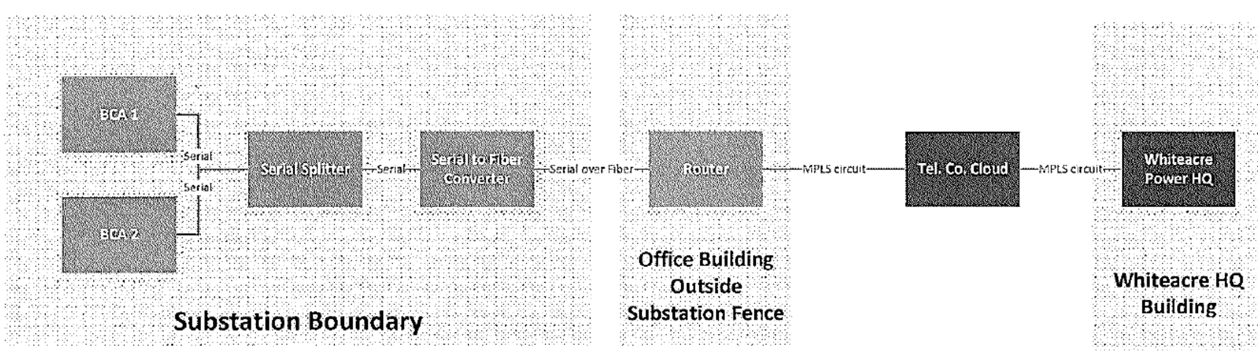
Under review. Response to be posted upon receipt.

7. Below is a generic substation diagram. The question is: Does this asset have external routable protocol, and if, is a firewall required?

Assumptions:

- Whiteacre Energy, a registered TO, GO, DP, etc., owns the substation and the Whiteacre HQ building, but not the Office building outside of the substation fence.
- The two BCAs inside the substation have been determined to be low impact BCAs (owned by Whiteacre).
- A national telephone company provider owns the "Tel. Co. Cloud" service that provides communications for the status/control BCAs in the substation.
- There is no routable communication in the substation boundary.
- The communication from the router to the cloud and back to HQ is routable.
- Whiteacre owns the BCAs, serial splitter, converter, and the router.

Question: After reviewing the above assumptions for this scenario, would the answer change at all if the router in the office building were moved into the substation boundary?



Under review. Response to be posted upon receipt.

8. FAC-003: The 2019 CMEP IP, noted that an increase in FAC-003 violations resulting in vegetation contacts had been observed. Is this trend still being seen?

RESPONSE: This trend is still being seen. Please refer to Drew Slabaugh's Fall Compliance Seminar presentation for FAC-003 Enforcement Trends.

9. FAC-003: Which current Best Practices, are seen as evidence of strong internal controls in a vegetation management program.

RESPONSE: The following are examples of some good practices SERC has seen during O&P audits on Vegetation Management.

The annual LiDAR patrol of BES Transmission facilities is the best in class. This shows a robust vegetation management program that provides detailed information about the vegetation growth rate within the respective ROW.

The Conductor blow out chart accounts for movement of conductor and depicts factors that consider movement of trees. This is one of the best depictions of a blow-out observed by the team.

The use and consideration of maintenance trigger clearances and conductor movement in relation to the rights-of-way boundaries is a well-designed process

The use of geospatial tracking for inspection, maintenance, and quality assurance are excellent controls to aid management's oversight of the vegetation management program

10. FAC-003: What documentation is necessary for the quarterly reporting of vegetation-related outages? If we don't have any items to report, is an attestation sufficient?

RESPONSE: Yes, an attestation is sufficient. Also, there is a check box that you can use on the Quarterly Report that indicates there is nothing new to report. The Vegetation Management Quarterly Form is located on the SERC portal.

11. PRC-005: We already have the narrative, based on last week's meeting with the System Protection group

RESPONSE: Electrically joined would be those facilities (lines, conductors, etc.) that are electrically connected to each other and are within the zone of protection for the relay scheme being applied.

12. PRC-027 R1.3.4 requires the following:

Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

The drafting team used the phrased "electrically joined". Could SERC communicate how many buses away "electrically joined" is?

R1 requires GO/TO/DP develop a process for developing new or revised protection system settings for BES elements. What does this process look like? Is it developed by all entities? Does each entity wait for the ISO to develop?

RESPONSE: Each entity must develop its own process that addresses each item under R1.

13. CIP-014: If a registered entity builds a new control center that is in scope of CIP-014 (replaces existing CIP-014 TCC) what is the specific timeline requirements for completion of interim R4/R5/R6 when it occurs in the middle of the 30 month period?

RESPONSE: The auditors would expect that planned facility replacements would be compliant upon commissioning. Such compliance could be reviewed as part of the Certification process, which occurs when control centers are replaced. This aligns with the other security standards (CIP-002 through CIP-011), which are required to be compliant upon commissioning for planned changes.

14. PRC-001, R1, requires GOP/TOP/BA familiar with the purpose and limitations of protection schemes. With the retirement of PRC-001, where does this requirement go for GOP/TOP/BA?

RESPONSE: Refer to the mapping document Project 2007-06.2 Phase II of System Protection Coordination.

15. TOP-001 Cables can be run in same tray as long as different "components". What is a "component"? (Ref recent NERC implementation guidance.

RESPONSE: Per the NERC Implementation Guidance and the supplemental material section found in the body of the Standard, infrastructure components include, but are not limited to: switches, routers, servers, power supplies, and network cabling.

16. Are NERC or SERC planning additional documented guidance on internal control implementation?

Under review. Response to be posted upon receipt.

Implementation Plans

17. Regarding NERC's proposal to consolidate ERO Enterprise-wide and Regional Entity-specific reliability risks into a single Implementation Plan, what if anything would remain in SERC's CMEP Implementation Plan?

RESPONSE: The 2020 ERO CMEP Implementation Plan does not include separate regional IP's. This was proposed by NERC, discussed and considered with the regions for several weeks, then collaboratively supported by the ERO in September. SERC, along with the other regions, will no longer have a regional CMEP IP beginning in 2020. The final posted 2020 CMEP IP addresses ERO-wide high risk areas. In lieu of a regional (SERC) CMEP Implementation Plan, regional specific risks will be considered in an entity's IRA. These considerations in the IRA will include SERC-specific risks identified by our committees.

Compliance Audits

18. Regarding NERC's proposal to grant Compliance Enforcement Authority (CEA) discretion as to when to conduct compliance audits and whether they will occur on the registered entity's site, under what circumstances would SERC allow an RC, BA or TOP to **not** have an on-site compliance audit?

RESPONSE: Anything we would say is speculation. However, the above proposal is part of a general review and revision of the NERC Rules of Procedure pertaining to CMEP activities. This is one of several proposed revisions in the ROP. If FERC approves this aspect of the ROP revisions, SERC will consider if a particular audit will require an onsite aspect to it. There are certain activities that tie with certain Standards that necessitate the audit team going onsite (control center tours, operator interview, validation for certain CIP standards, FAC-008 substation/control center visits, etc.). It would depend on the results of an entity's IRA and the facts and circumstances of each audit.

19. Because NERC proposes to no longer require the posting of an Annual Audit Plan, would SERC contemplate also to no longer provide schedules of planned audits in the year preceding planned audits? Would SERC contemplate **not** notifying entities of on-site compliance audits with prior notice greater than the required 90-day notice?

RESPONSE: SERC will continue to make available the upcoming years' audit schedule without the actual dates of the audit. SERC will continue to reach out to an entity in the year preceding the planned audit, to inform the entity of the proposed onsite audit dates for the upcoming year. SERC does not contemplate not notifying a registered entity less than 90 days, unless the monitoring method is a Spot Check, in which notification should be "at least 20 days" out.

20. For those entities that employ LiDAR, if a LiDAR analysis under load, e.g., thermal and/or wind, indicates a vegetation encroachment into the MVCD, does the entity have a self-report, e.g., R1.1 or R2.1?

RESPONSE: Yes. A self-report would be warranted if it is determined that vegetation has encroached within the MVCD.

21. It was noted during the SERC presentation that lack of training or proper certification was a cause of some of the recent vegetation outages. There was a requirement, R1.3, in FAC-003-1 (now retired) for qualified and trained personnel to perform vegetation work. Is SERC planning to push for this Requirement to be added into a revised Standard and potentially submit a SAR on such a topic if there is an actual reliability need for this?

Under review. Response to be posted upon receipt.

22. I understand that SERC stated that they need to discuss this question with NERC, however, because they are unable to answer this question at this time and it does not appear that they will have an answer in the near term, I would like to "cover" ourselves until an interpretation is provided and so I would like to submit the question with the caveat we are aware that SERC needs to consult with NERC before providing a response.

Q: In SERC's posted FAQs for PRC-005, SERC has posted lessons learned language stating that for shared facilities, a TO is responsible for adding a battery bank that it does not own into its Protection System program (see image below). Can SERC provide additional information on what SERC is wanting to see from the TO that does not own a battery bank (it's owned by a separate TO) in its Protection System program?

Thank you.

Under review. Response to be posted upon receipt.

23. For PRC-005-6, what is the required evidence to maintain? The most recent test report and only the date of the previous maintenance activity or test reports for both maintenance activities?

Under review. Response to be posted upon receipt.

24. TOP-001 R20-R24, what is an acceptable or reasonable time frames to have each and all components of data exchange infrastructure tested.

a. Is there a maximum or discouraged time frame not to go over.

b. Does all equipment need to be tested in 90 days?

Under review. Response to be posted upon receipt.

25. Added question regarding the IRA/COP presentation: Has SERC considered adopting or developing a maturity model as part of the entity risk assessment? Having a framework/model for entities to follow would reduce many of the questions and ambiguity over risk assessment, and provide a path forward on how to reduce risk.

RESPONSE: SERC implements the same IRA and COP processes agreed to by NERC and the other regions so that there is consistency across regions. We follow the guidelines from NERC.