« *Technical Rationale for Reliability Standard* » (Justification technique) (FAC-011-4, FAC-014-3, IRO-008-3, PRC-002-4 et TOP-001-6) (version anglaise)

Technical Rationale for Reliability Standard FAC-011-4

April 2021

FAC-011-4 – System Operating Limits Methodology for the Operations Horizon

Requirement R1

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1 Part 1.1 in currently-effective FAC-011-3 requires the SOL methodology "be applicable for developing System Operating Limits (SOLs) used in the operations horizon." The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1 Part 1.2 in currently-effective FAC-011-3 requires the SOL methodology to "state that SOLs shall not exceed associated Facility Ratings." Facility Ratings to be used in operations as SOLs are addressed through FAC-011-4 Requirement R2 and therefore, is not addressed as a subpart of R1.

Requirement R1 Part1.3 in currently-effective FAC-011-3 requires the SOL methodology to "include a description of how to identify the subset of SOLs that qualify as IROLs." This language is preserved in Requirement R7.

Requirement R2

R2. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission

Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still the functional entity responsible for determining Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between RCs and their TOPs during operations.

Requirement R3

R3. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

- **3.1.** Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;
- **3.2.** Require that System Voltage Limits respect voltage-based Facility Ratings;
- **3.3.** Require that System Voltage Limits are greater than or equal to in-service BES relay settings for under-voltage load shedding systems and Undervoltage Load Shedding Programs;
- **3.4.** Identify the minimum allowable System Voltage Limit;
- **3.5.** Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection;

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within each RC Area. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its RC Area for voltage-based Facility Ratings, voltage instability, voltage collapse and misactuation of relay elements.

Both maximum and minimum limits are required. Maximum limits tend to be associated with equipment/facility limitations. Minimum limits are often used to prevent phenomena associated with minimum voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of “System Voltage Limits”, both maximum and minimum, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used. The terms maximum and minimum are used through the standard, rationale and definitions with regard to voltage limits however it is common in industry to use the terms low, lowest, high and highest as synonyms for maximum and minimum and such usage is acceptable.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage Limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from maximum voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Part 3.5 requires that the SOL methodology define a method for determining common System Voltage Limits between RCs and TOPs. RC and TOPs may independently identify System Voltage Limits which if not coordinated could create reliability issues. An example could be where one TOP A chooses very wide System Voltage Limits on its equipment but TOP B could have much tighter System Voltage Limits even within the same substation. TOP A may operate equipment that are within its System Voltage Limits but cause an exceedance of TOP B's equipment. Coordinating the System Voltage Limits in these circumstances can prevent unnecessary exceedances of the System Voltage Limits.

Part 3.2 provides that in establishing System Voltage Limits, the SOL methodology shall respect any voltage-based Facility Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any voltage-based Facility Ratings for facilities that terminate at, or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that Undervoltage Load Shedding Programs (UVLS) should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL methodology shall ensure System Voltage Limits are not set at values less than UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall:

- **4.1.** Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:
  - **4.1.1.** steady-state voltage stability;
  - **4.1.2.** transient voltage response;
  - **4.1.3.** angular stability; and
  - **4.1.4.** System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5. Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic, and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of System damping.

Also included in Part 4.1 is language requiring the SOL methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations. Many stability tools will consider a subset of contingencies that are applicable to the area in study and are expected to produce more severe System impacts rather than every single potential contingency to set the limits conservatively while minimizing the time it takes to complete the solution, which is reflected in the phrase "applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES". In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, the SOL methodology could describe which TOP or RC has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance. Additionally, Requirement R4 Part 4.3 addresses when there is an impact to other Reliability Coordinator Areas.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL methodology. For example, the SOL methodology could state that stability limits will be determined for any combination of all facilities in and single facility out conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10 percent, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirement R3 Parts R3.1 and R3.4 into a single part while providing flexibility to the extent of the RC Area (including other RC Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require the modeling of the entire Reliability Coordinator Area to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) programs are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.7, UFLS programs or UVLS Programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS programs and UVLS Programs as measures of "last resort system preservation".

Requirement R5

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing

Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall:

5.1. Specify the following single Contingency events:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2 Part 2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3 Part 3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in FAC-011-3 Requirement R2 Part 2.2 and Requirement R3 Part 3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in the evaluation of post-Contingency state in OPAs and RTAs (thermal and voltage). The SOL methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that, at a minimum, must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events, such as inadvertent breaker operation and bus faults, may be considered if the probability of such an event is relevant. These Contingencies, if any, must be specified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Part 5.3 compliments the proposed Requirement R8 in FAC-014-3 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R5 establishes the contingency events for use in determining stability limits, in performing Operational Planning Analysis (OPAs), and in performing Real-Time Assessments (RTAs). The standard requirement is not meant to imply that all TOPs within the RC footprint must use that identical list spanning the entire RC region but may use a reduced list that at least covers the area they are responsible for the most limiting Contingencies.

Requirement R6

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses:

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in Reliability Coordinator's SOL methodology are met.

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

Rationale R6

Requirement R6 addresses BES performance criteria, which is addressed in the currently effective FAC-011-3 Requirement R2 Parts 2.1 and 2.2. The proposed requirement has some differences in the manner in which the performance criteria are addressed and in the level of detail reflected in the requirement when compared to the existing requirement. Those differences are discussed here.

Currently effective FAC-011-3 Requirement R2 states that the "*RC's SOL methodology shall include a requirement that SOLs provide BES performance consistent with the following.*" The subsequent subparts to FAC-011-3 Requirement R2 further describe pre-Contingency performance criteria (in Requirement R2 Part 2.1), the post-Contingency performance criteria (in Requirement R2 Part 2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in Requirement R2 indicates that the SOLs established in accordance with Requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of Requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011-3 Requirement R2 and its subparts.

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, the pre- and post-Contingency states are assessed on an ongoing basis as part of Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations through the application of the minimum performance criteria specified in FAC-011-4 requirement R6 and subparts. Under this construct, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the OPA and RTA for Facility Rating and System Voltage Limits. Stability limits are either established prior to the OPA/RTA or established and assessed during the OPA and RTA.

Requirement R6 works together with proposed TOP-001-5 Requirement R25 and IRO-008-3 R7 to support reliable operations for pre- and post-Contingency operating states. TOP-001 Requirement R25 states, *"Each Transmission Operator shall use the applicable RC's SOL methodology when* *determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis."* IRO-008-3 Requirement R7 states*, "Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis."* The above noted requirements in TOP-001 and IRO-008 ensure that the performance framework identified in the SOL methodology is used to determine SOL exceedances consistently between the RC and its associated TOPs during Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis."

FAC-011-4 Requirement R6 Parts 6.1.1 and 6.1.2 are intended to prescribe the appropriate use of Emergency Ratings and Emergency System Voltage Limits when actual (or OPA no Contingency) flows or voltages exceed Normal Ratings or fall outside normal System Voltage Limits, respectively.

The language in Part 6.1.1 reflects the concepts in Figure 1 of the Project 2014-03 Whitepaper (NERC SOL Whitepaper) with regard to Facility Rating performance. Part 6.1.1 states, *"Steady state flow through Facilities are within applicable Emergency Ratings, provided that System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings."* This is intended to allow, as an example, for the use of the 4-hour Emergency Rating and the 15-minute Emergency Rating consistent with the bullet descriptions in Figure 1. As is described in Figure 1, the use of the Emergency Ratings is governed by the amount of time it takes to execute the Operating Plan to mitigate the condition. The portion of Part 6.2.1 that states, *"Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating"* is intended to specifically address the operating state highlighted in yellow in Figure 1. In this operating state, the System Operator may have insufficient time to implement post-Contingency mitigation actions (i.e., actions that are taken after the Contingency event occurs); therefore, pre-Contingency mitigation actions consistent with the Operating Plan must be taken as soon as possible to reduce the calculated post-Contingency flow. However, as noted in the NERC SOL Whitepaper, pre-Contingency load shed may not be necessary or appropriate when assessment identifies that the impact is localized.

Requirement 6 applies only to those contingencies specified by the Reliability Coordinator for monitoring in the Transmission Operators RTA and OPA. If the Transmission Operators monitors additional contingencies beyond the subset required by the Reliability Coordinator, they are not required to meet the performance metrics in Requirement 6. As an example, if a TOP chooses to monitor loss of an entire substation as a contingency within their contingency analysis this section does not require that system performance following that event must meet these performance requirements. If the loss of a substation was not a defined contingency in the RC's SOL methodology, and no other defined contingency could cause loss of the entire substation, then the TOP could define what performance criteria, if any, to apply to this contingency. Said simply, R6 specifically applies only to the events and conditions described in R5.

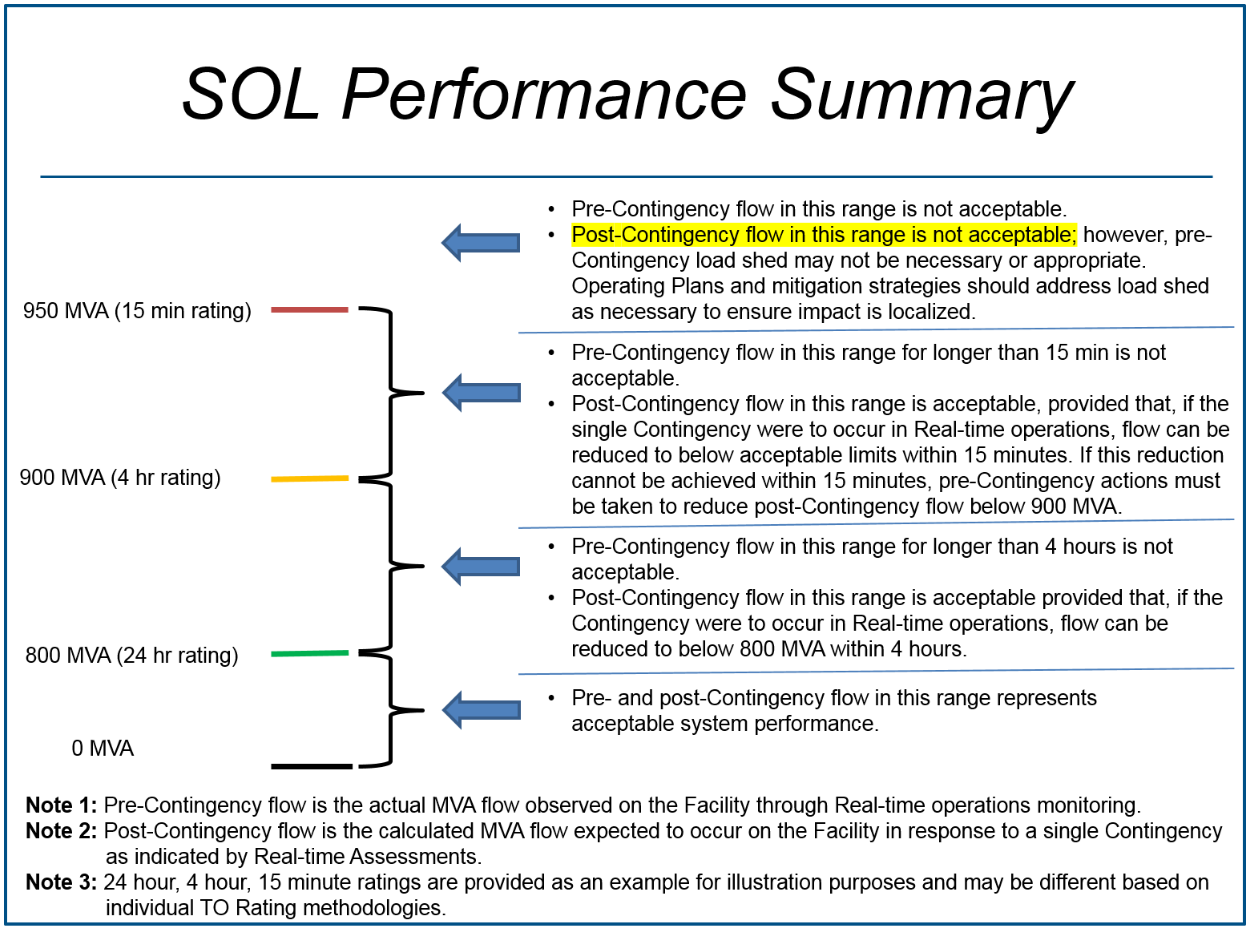

Figure 1 of the NERC SOL Whitepaper

The footnote referenced in Parts 6.1.4 and 6.2.3 states, "*Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.*" This helps to provide clarity that there are multiple methods to assessing if System performance demonstrates that Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. Some entities determine stability limits across a variety of operating conditions and apply the appropriate limit to the operating condition in the OPA, RTA and Real time monitoring. Other entities may utilize tools that run at the time of the study to assess for acceptable performance or determine stability limits at the time of the OPA or RTA. Others may yet utilize other offline analysis techniques.

Part 6.3 recognizes the potential for regional differences and is intended to describe the minimum performance criteria for Contingency events that are more severe than the single Contingency events listed in Requirement R5 Part 5.1.1 for OPAs and RTAs (i.e., Contingencies identified in Part 5.2). Per Part 6.3, if any of these more severe Contingency events were to occur, at a minimum the System is expected to remain stable, there should be no Cascading, and there should be no uncontrolled separation that adversely impact the reliability of the Bulk Electric System.

Part 6.4 maintains the concept identified in FAC-011-3 Requirement R2 Part 2.3.2 and intent of FERC Order No. 705, where FERC determined that load shedding shall only be utilized by system operators as a measure of last resort to prevent cascading failures. Part 6.4 clarifies that load shedding as a remedy in the operating plan should only be allowed by the RC's methodology after other options are exercised without regard for financial impact. The term "planned manual load shedding" refers to the inclusion of planned post-Contingency shedding of load either manually or by automated methods in an Operating Plan. This Operation Plan is developed in response to SOL exceedances identified in its Operating Planning Analysis including for contingencies identified in Requirement R5 against the transmission system under study and would apply to the Operational Planning Analysis. While those plans guide an operator's response to an event in Real-time monitoring or a Real-time Assessment, Part 6.4 would not directly apply to the actions taken by the operator in real time.

For clarity, the following examples of pre- or post-Contingency actions are provided to expand on the term "all other available System adjustments" that should have been made prior to planning to utilize load shedding:

- Generation commitment and re-dispatch regardless of economic cost, when the generation has a significant impact on the SOL exceedance.
- Curtailment and adjustment of Interchange regardless of economic cost, when the Curtailment or adjustment of Interchange has a significant impact on the SOL exceedance.
- Transmission re-configuration (only if studies shows that the re-configuration does not put more load at risk or create other unacceptable system performance)

Transmission re-configuration that does place more load at risk or create other unacceptable system performance issues is not required to be used prior to planned manual load shedding. As an example the reconfiguration of a looped network into a series of radial connections to avoid planned post contingency manual load shedding could be a re-configuration that puts more load at risk. In those circumstances the TOP and RC must select that option that best fits their operating conditions and Requirement R6 Part 6.4 is not intended to prescribe one approach over the other. Planned "manual" load shedding would be load shed plans, as part of an Operating Plan, and is load that would be shed as part of an Operator Instruction or taking action to shed the load in Real-time. Reconfiguration of a system in Real-time to avoid or lessen the amount of planned manual load shed or reconfiguration of a system in Real-time that creates additional "consequential" load loss is not part of "planned manual load shedding". Furthermore, the "all other available System adjustments" would apply only to those adjustments studied by the TOP or RC at the time of the Operating Planning Analysis and not to system adjustments that might be found during a post event review days or weeks later. Part 6.4 is an addition to the RC's SOL methodology and the RC can provide additional clarity as appropriate to their circumstances.

Planned manual load shedding in the context of Requirement R6 Part 6.4 is specific to what could be considered "firm" load, and would not include non-firm load, interruptible load, or any other load that has an arrangement that allows the load to be shed or interrupted when needed.

Requirement R7

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include:

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1. IROL exceedances

7.1.2. SOL exceedances of stability limits;

7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation

7.1.4. Pre-contingency SOL exceedances of Facility Ratings

7.1.5. Pre-contingency SOL exceedances of normal minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits

7.2.2. Pre-contingency SOL exceedances of normal maximum System Voltage Limits.

Rationale R7

The changes in proposed FAC-011-4 help to provide clarity by requiring a performance framework for determining SOL exceedances in the RC's SOL methodology. This provides better uniformity in determining what is and isn't an SOL exceedance. This clarity may increase the instances of what is determined to be an SOL exceedance and thus increase the instances of communications that are required consistent with TOP-001-4 Requirement R15 (as well as IRO-008-2 Requirements R5 and R6) which states, "*Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.*"

Concerns were raised as to the effect on Real-time System Operators being required to communicate every SOL exceedance, especially those which were considered short duration SOL exceedances (e.g. less than 15 min, 30 min). This could be a significant increase for entities that historically performed RTAs more frequent than the required 30 minutes. Proposed FAC-011-4 Requirement R7 addresses this concern by requiring the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure consistency within an RC's area between the RC and its TOPs.

Part 7.1 requires that the risk based approach require that "IROL exceedances, SOL exceedances of stability limits, post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation and pre-contingency SOL exceedances of Facility Ratings and pre-contingency Minimum System Voltage Limits will always be communicated". While typically less frequent, these subset of SOL exceedances were determined to be of a higher risk and must always be communicated between TOP's and RC's. The RC must identify the priority of communications during circumstances where multiple SOL exceedances may exist.

Part 7.2 requires that the risk based approach require that "Post-contingency SOL exceedances of Facility Ratings and System Voltage limits and pre-contingency Normal Maximum System Voltage Limits must be communicated, if not resolved, within a timeframe identified by the RC which cannot exceed 30 minutes". While typically more frequent, these subset of SOL exceedances were determined to be of a lower risk allow the RC to identify a timeframe which cannot exceed 30 minutes whereby if the SOL exceedance is mitigated (no longer an SOL exceedance) within the identified timeframe (e.g. 15min, 30 min, etc.), the SOL exceedance would not be required to be communicated to the TOP or RC. The RC must identify the priority of communications during circumstances where multiple SOL exceedances may exist.

Nothing prohibits an RC from requiring all or an additional subset of SOL exceedances than what is identified in Part 7.1 from being communicated. Nothing prohibits a Real-time System Operator from communicating beyond what is required or in line with other good utility practice (e.g. troubleshooting or communicating). These provisions are meant to ensure that a risk based approach can be applied to prevent low risk or after the fact communications from distracting System Operators from other higher priority tasks.

This proposed requirement is coordinated with proposed changes to TOP-001-5 Requirement R15 which states "*Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded* ***in accordance with its Reliability Coordinator's SOL methodology.***" and with proposed IRO-008-3 Requirements R5 and R6 which state, **"***Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded* ***in accordance with its Reliability Coordinator's SOL methodology****."* and **"***Each Reliability Coordinator shall notify****, in accordance with SOL methodology****, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.***"***,** respectfully.

Requirement R8

R8. Each Reliability Coordinator shall include in its SOL methodology:

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.

Rationale R8

The two IROL related requirements in FAC-011-3 were preserved under Requirement R8. Part 8.2 utilizes terminology consistent with proposed FAC-011-4, and the IRO/TOP NERC Reliability Standards by replacing "violating" with "exceeding". It also inserts "exceeding" before the IROL to better harmonize with proposed FAC-011-4, and the IRO/TOP NERC Reliability Standards.

Requirement R9

R9. Each Reliability Coordinator shall provide its SOL methodology to:

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

Rationale R9

Requirement R9 preserves the reliability objective of providing the SOL methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R8 Part 8.1 mandates that an RC provide its SOL methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL methodology. Additionally, requirement 9 Part 9.2 enforces provision to those entities that would require notification of an update or change to the RC's SOL methodology.

In Requirement R9 Part 9.2.2, Planning Coordinator (PC), not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R9 Part 9.2.2 also uses "responsible for planning" instead of "models any portion of" to distinguish those PCs and Transmission Planners (TPs) who have a reliability-related need from a PC/TP who simply has acquired a model that contains a portion of the RC Area, but does not plan for that area. Requirement R9 Part 9.2.4 differs from Requirement R9 Parts 9.2.1 through 9.2.3 in that it mandates provision of the SOL methodology to non-adjacent RCs that have specifically requested to receive updates, and indicated they had a reliability-related need.

Technical Rationale for Reliability Standard FAC-014-3

April 2021

FAC-014-3 – Establish and Communicate System Operating Limit

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs for its portion of the Reliability Coordinator Area, and that these SOLs must be established in accordance with the RC's SOL methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under Requirement R2) to the RC. The TOP should refer to the RC's documented data specification necessary for the RC to perform Operational Planning Analyses, Real-time monitoring and Real-time assessments under IRO-010-2 for any guidance or requirements regarding the provision of SOLs from the TOP. For example, the RC may wish to specify the periodicity and format in which the data should be communicated. The RC may choose to also provide this or any additional guidance within its SOL methodology. If no such information is given, the TOP may provide SOLs as per other terms agreed upon with the RC.

This requirement was previously covered under FAC-014-2 Requirement R5.2 but was moved to a more logical position in the standard, immediately following Requirement R2 for establishing SOLs.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2. However, the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA), Real-time Assessment (RTA) and Real-time monitoring. In such instances, the timing requirements should be coordinated between the data specification document and the RC's SOL methodology.

Requirement R3 sets a common expectation across industry of the minimum actions any TOP must take when communicating SOLs to their RC. It's important for this requirement to remain within FAC-014-3 to ensure SOLs are communicated from the TOP to the RC in case IRO-010-2 is modified or removed in future revisions to the standards.

Requirement R4

Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits when the limit impacts more than one TOP in its RC Area. This ensures that the RC, who has wide-area responsibility, will establish such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to establish stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area). The requirement establishes the end condition, which is the RC being responsible for establishing a stability limit that impacts more than one TOP regardless of whether that stability limit was originally calculated by the RC or one of the impacted TOPs. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s)or TOP(s) appropriately in accordance with other NERC standards requiring the communication of SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5, IRO-014-3 Requirements R1.4 and R1.5 and FAC-014-3 Requirement R5.3). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

RCs who have asynchronous connections should consider the impact of all possible transfer levels across those connections including when those connections are not available if lost by contingency or forced outage.

Requirement R5

Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs), Transmission Planners (TPs) and Transmission Operators (TOPs). This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause for RCs to provide SOLs when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-2) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed in IRO-014-2. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the impacted PCs and TPs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC and the TP the relevant information necessary for their annual assessments; however nothing precludes the PC and TP from requesting this information more frequently. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs and TPs with additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

In addition, Requirement R5 Part 5.2.5 requires the RC to provide the impacted PCs and TPs with unique system conditions associated with a particular stability limit or IROL as opposed to generic study conditions directed at covering all (or a group of) stability limits which may be included in the RC's SOL methodology as required by, Requirement R4 Part 4.4 in FAC-011-4. For example, where the RC's SOL methodology may describe that stability limits must be verified for "summer peak", "winter peak", "minimum demand" and "shoulder periods", the information provided under , Requirement R5 Part 5.2.5 would identify whether the particular stability limit was present in all or just one of those conditions.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s) or TOP(s) appropriately in accordance with other NERC standards requiring the communication SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5 and IRO-014-Requirements 1.4 and 1.5)). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. For example, in deriving a new SOL that may impact adjacent TOPs, a TOP may need more information from the RC on related SOLs in other TOP areas within the region that could impact their derivation. Requirement R5, Parts 5.3 through 5.5, require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Finally, Requirement R5, part 5.6, requires that the RC must provide each impacted Generation Owner or Transmission Owner within its Reliability Coordinator area with a list of Facilities that they can use to satisfy the criteria in Attachment 1 part 2.6 in CIP-002 and 4.1.1.3 in CIP-014. Of the three possible entities, RC, TP and PC listed in CIP-002 and CIP-014 that could deliver this information to the TOs and GOs, the RC is ultimately responsible given they're required to establish IROLs. Thus, the requirement for provision of the list of Facilities identified as critical to the derivation of an IROL and its associated critical contingencies should rest with the RC. The SDT also felt that some known periodicity of information provision, per this requirement, seemed appropriate. After industry comment, an annual periodicity was chosen. This timeframe should allow sufficient analysis to document IROLs that will persist, and need monitoring by the RC and any necessary action by asset owners, per the CIP standards. Those IROL like conditions which may manifest in real time, due to forced outages are not appropriate for consideration until reviewed by the RC to determine if they are to be established as an IROL to prevent the condition from reoccurring, and warrant reporting per the standard.

Requirement R6

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator's SOL methodology.

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

Rationale R6

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R6 was drafted to ensure the appropriate use of applicable Facility Ratings, System steady-state voltage limits, and stability performance criteria in operating and planning models. Analysis of these models determine System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of Facilities when they are placed in service.

Requirement R6 provides a mechanism for the coordination of Facility Ratings, System steady-state voltage limits, and stability performance criteria in planning models to those established in accordance with the RC's SOL methodology. Since the analysis of planning models determines what Facilities are constructed or modified, the application of Facility Ratings, System steady-state voltage limits, and stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL methodology. Otherwise, operators could be unduly limited by constraints that were not identified in preceding planning studies.

The Near-Term Transmission Planning Horizon is specified because assumptions regarding the topology of the transmission system, forecast load and generation, etc. are more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be in the implementation phase or finalized in this period.

Facility Ratings:
Reliability Standard MOD-032 requires the modeling data in a PC area be coordinated between the PC and applicable TP. It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means for consistency between the PC and TP in ensuring Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL methodology. This is important because Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The intent of Requirement R6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor allow the PCs nor TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology. This is not intended to imply the RC has authority over the PCs and TPs planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting Facility Ratings than those established in accordance with the RC's SOL methodology. As such, Requirement R6 explicitly allows for exceptions when a technical rationale is provided to the appropriate entities in accordance with the requirement. The obvious example for such an exception is a facility where the PC / TP has assumed an upgrade which increases the Facility Rating (typically, the thermal limit) of the equipment in question.

Furthermore, it is the SDT's intent to clarify that Facility Ratings that result from variables such as the implementation of future Corrective Action Plans, or the use of ambient temperature assumptions in seasonal planning models that differ from those ambient weather assumptions used in operational analyses and monitoring in real time, may be used. Although they may be less limiting than those in the RC's SOL methodology in certain instances, it is understood that seasonal assumptions and capacity increases due to upgrade are appropriately included in future planning models. These provisions should be included in the documented technical rationale provided to the appropriate entities in accordance with the requirement.

System Steady-State Voltage Limits:
Regarding voltage performance criteria, the intent of this requirement is to supplement Requirement R5 of TPL-001-4 which states, "Each TP and PC shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R5, PCs and TPs are required to implement the process described in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Stability Performance Criteria:
Regarding stability performance criteria, the intent of this requirement is to supplement the performance of stability analysis by the PC and TP per TPL-001. When PCs and TPs perform the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R7

Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning

Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include:

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

Rationale R7

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment and the associated Corrective Action Plan, do not provide for the level of detail prescribed in FAC-014-3 Requirement R7. Therefore, this requirement was drafted to ensure the appropriate details regarding any potential instability identified in the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and TOPs.

The information itemized in FAC-014-3 Requirement R7 is a key consideration for RCs and TOPs in the establishment of SOLs. For example, a study might indicate that System instability was avoided through the implementation of an operational measure, or Remedial Action Scheme (RAS). In this example, if the operational measure or RAS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent instability. Without this information, operators may be unaware of these risks and the measures required to address them. Existing FAC-014-2, Requirement R6 requires similar, though less detailed, information is shared by the planning with the RC. The SDT believes FAC-014-3, Requirement R7, improves upon this requirement and provides added clear and concise information to its impacted RCs and TOPs.

In addition, FAC-014-3 Requirement R7 Part 7.4 is useful information which supports FAC-014-3 Requirement R8. The information from Requirement R8 supports a number of other standards which require the PC and TP to provide information regarding instability, Cascading, and uncontrolled separation that adversely impacts the reliability of the BES to the TO and GO.

Requirement R8

Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.

Rationale R8

This requirement was drafted to ensure the appropriate details (i.e. Facilities) regarding potential instability, Cascading, or uncontrolled separation identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted Transmission and Generation Owners. Impacted Transmission and Generation Owners consist of those entities who have facilities requiring notification and **does not** imply that all Transmission and Generation Owners need notification of whether they have facilities requiring notification or not. This is necessary to ensure Facility owners receive this input to identify the Facilities that, as required by other Reliability Standards, require some level of protection, hardening, or increased vegetative management provisions. This requirement further supports the SDT's proposed changes to other Reliability Standards being updated to account for the retirement of FAC-010.

Furthermore, this requirement addresses the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. This requirement, coupled with Requirement 5.6, provides annual notifications to Facility owners from both operating and planning entities, whereas no such timely notification requirements exist in the standards today.

Technical Rationale for Reliability Standard IRO-008-3

April 2021

IRO-008-3 – Reliability Coordinator Operational Analyses and Real-Time Assessments

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board of Trustees approval, the text from the rationale text boxes was moved to this section.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:
Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

Rationale for R2 and R3:
Requirements added in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

Rationale for R5 and R6:
In Requirements R5 and R6 the use of the term ‘impacted’ and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications. The use of the terminology “in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. For example, the SOL methodology could state that an RC and TOP sharing with each other

real time monitoring and RTCA output information could provide clear communication and indications of when SOL exceedances appear and are mitigated in real time, meeting the requirements of the standard.

Rationale for R7:

Requirement R7 was added to align the Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis activities with the RC's SOL methodology. This will ensure that methods and frameworks that surround what is required in the SOL methodology are utilized during these activities (e.g. contingencies utilized, stability criteria, performance framework, etc.) in determining SOL exceedances.

Technical Rationale for Reliability Standard PRC-002-4

April 2022

PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for Requirement R1

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the Disturbance Monitoring Standard Drafting Team's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-4, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three-phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;

2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.
5. Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three-phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).

5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B and C are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1600 MVA, 1500 MVA and 1550 MVA respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1550 MVA, 1675 MVA and 1600 MVA respectively. The bus B is the one with highest maximum three phase short circuit MVA now. The three phase short circuit MVA of bus B is within 15% of the three phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1500 MVA, 1750 MVA and 1650 MVA respectively. The three phase short circuit MVA of bus B is greater than 15% of three phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of “directly connected” BES Elements are notified. For the purposes of this standard, “directly connected” BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 1 and 2 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

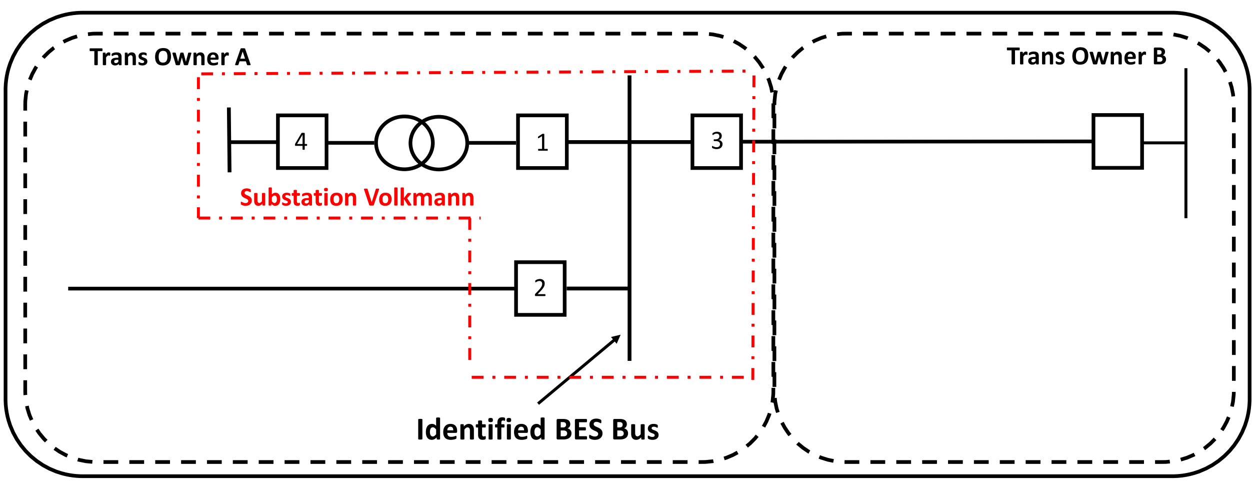

Figure 1: Straight Bus Configuration – Single Owner

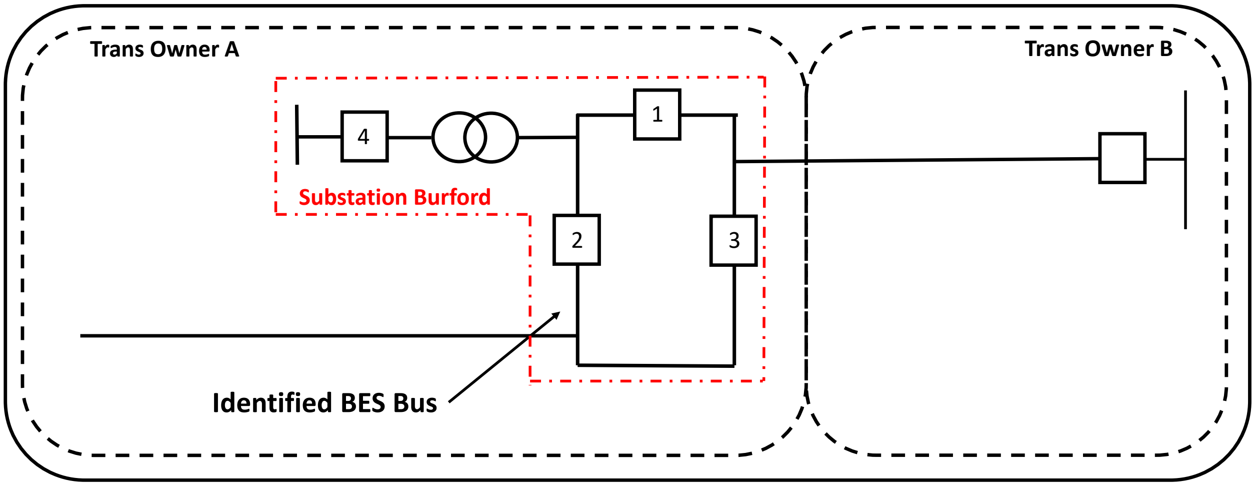

Figure 2: Ring Bus Configuration – Single Owner

Figures 3 and 4 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

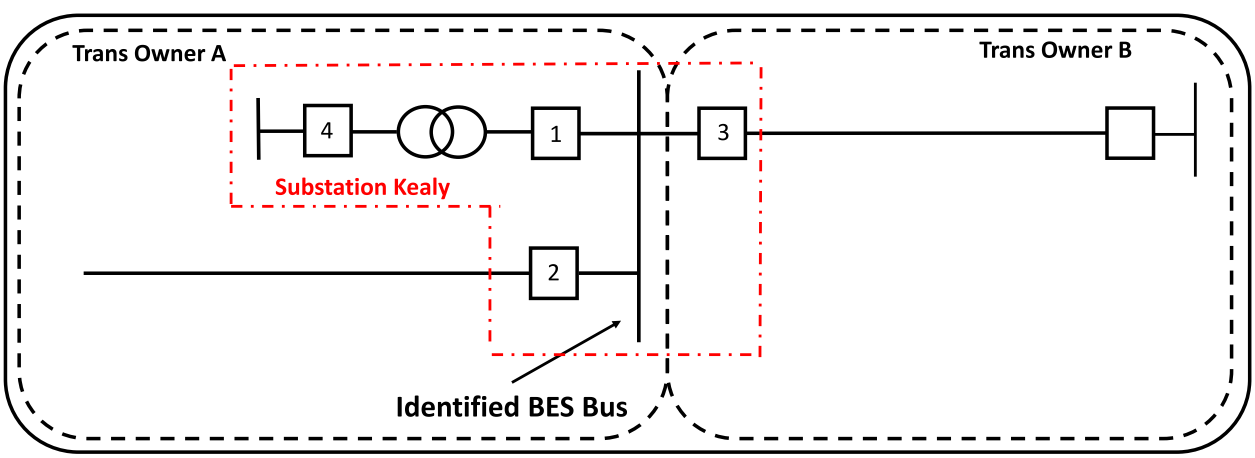

Figure 3: Straight Bus Configuration – Multiple Owners

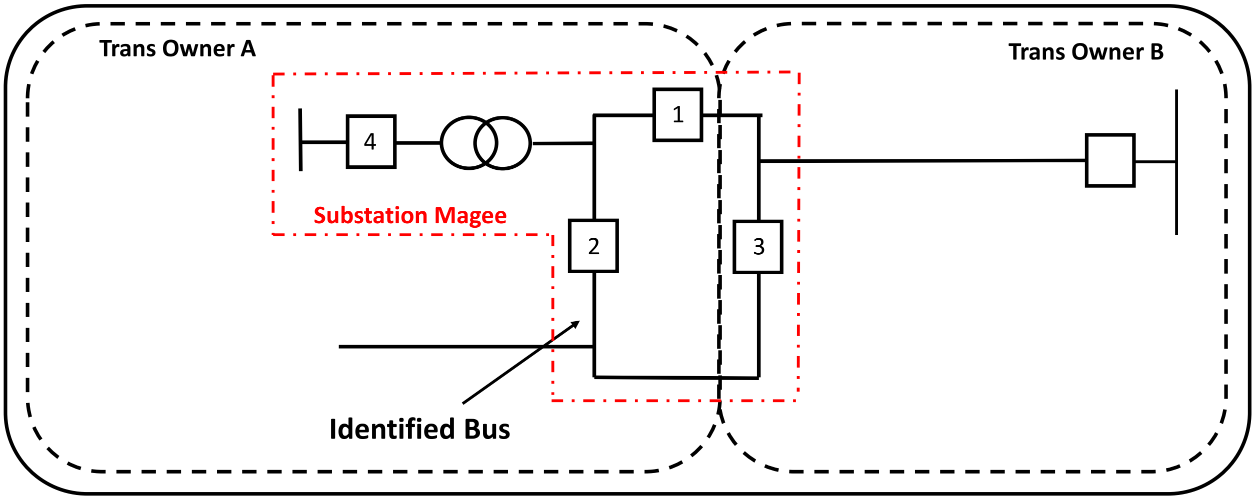

Figure 4: Ring Bus Configuration – Multiple Owners

For examples in Figures 3 and 4, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 5 shows an example with a generator interconnection. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

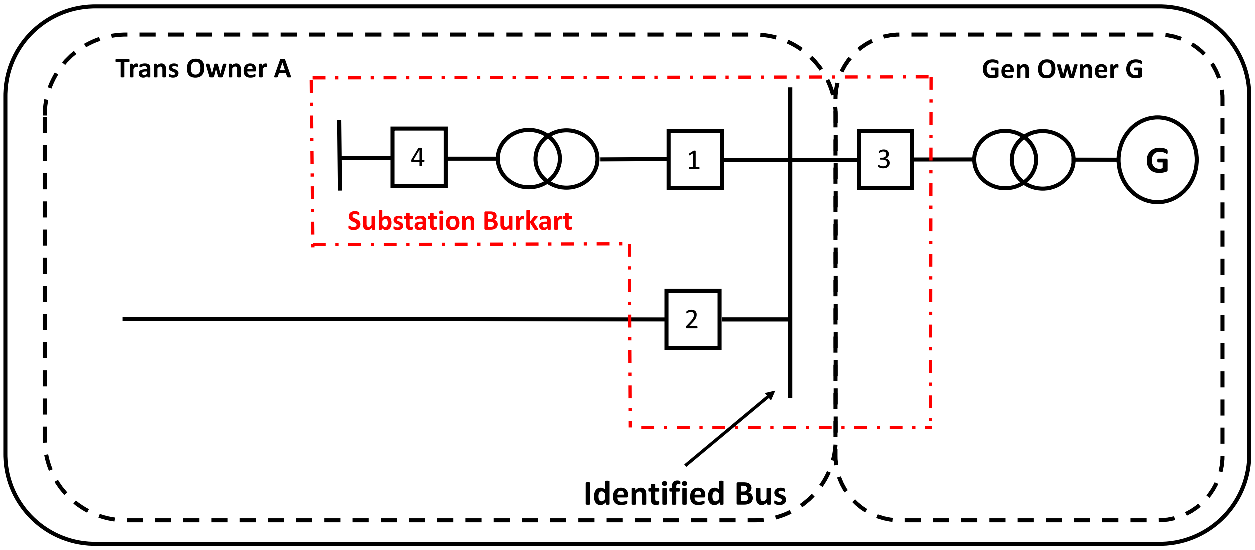

Figure 5: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 6, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

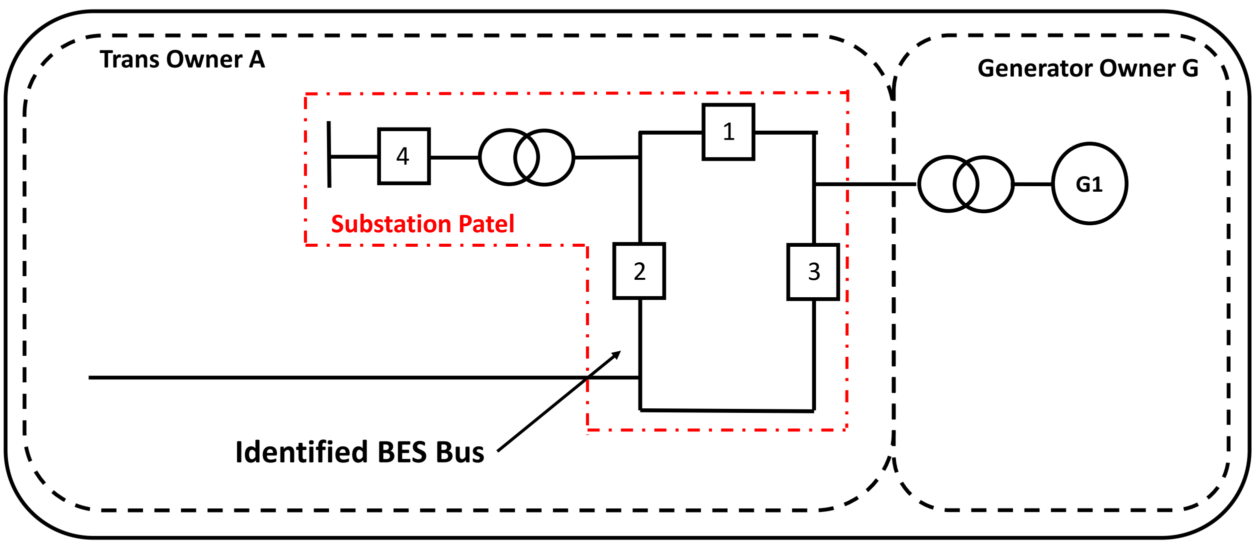

Figure 6: Generator Interconnection to Ring Bus

Figure 7 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

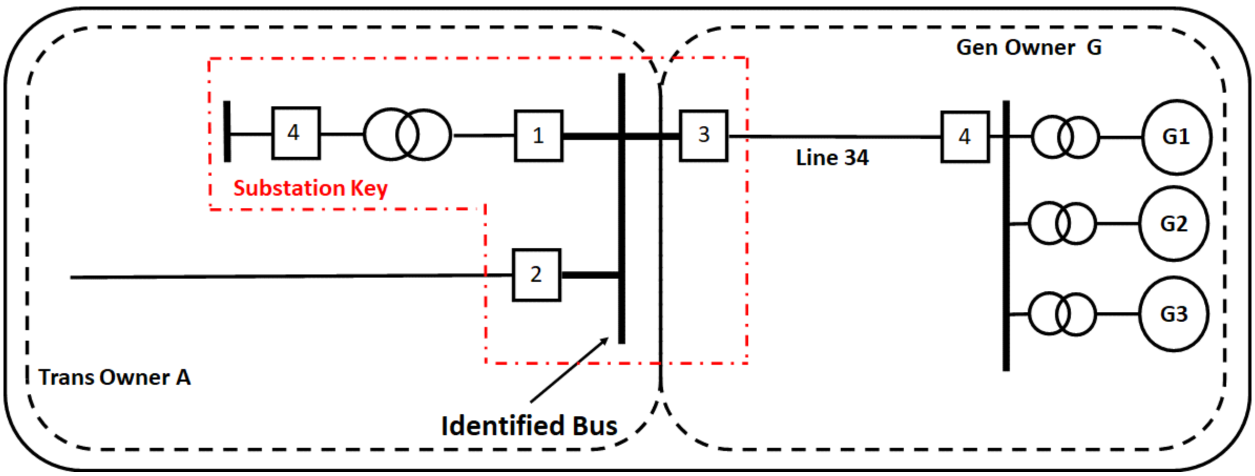

Figure 7: Generator Interconnection via Line 34

Figure 8 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3 and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

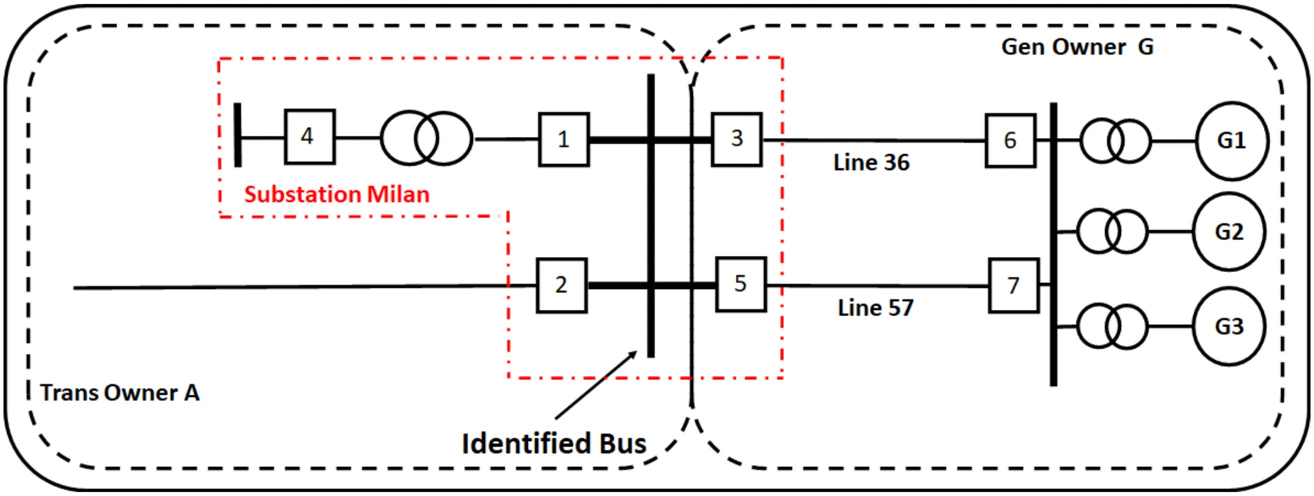

Figure 8: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification_TransmissionOwnerB

Greetings,

In accordance with NERC Standard PRC-002-4, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Rationale for Requirement R2

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element directly connected to a BES bus. Change of state of circuit breaker position and time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position.

However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Examples in Figures 9, 10 and 11 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement R3

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements directly connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element directly connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities, it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

Examples in Figures 9, 10, and 11 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

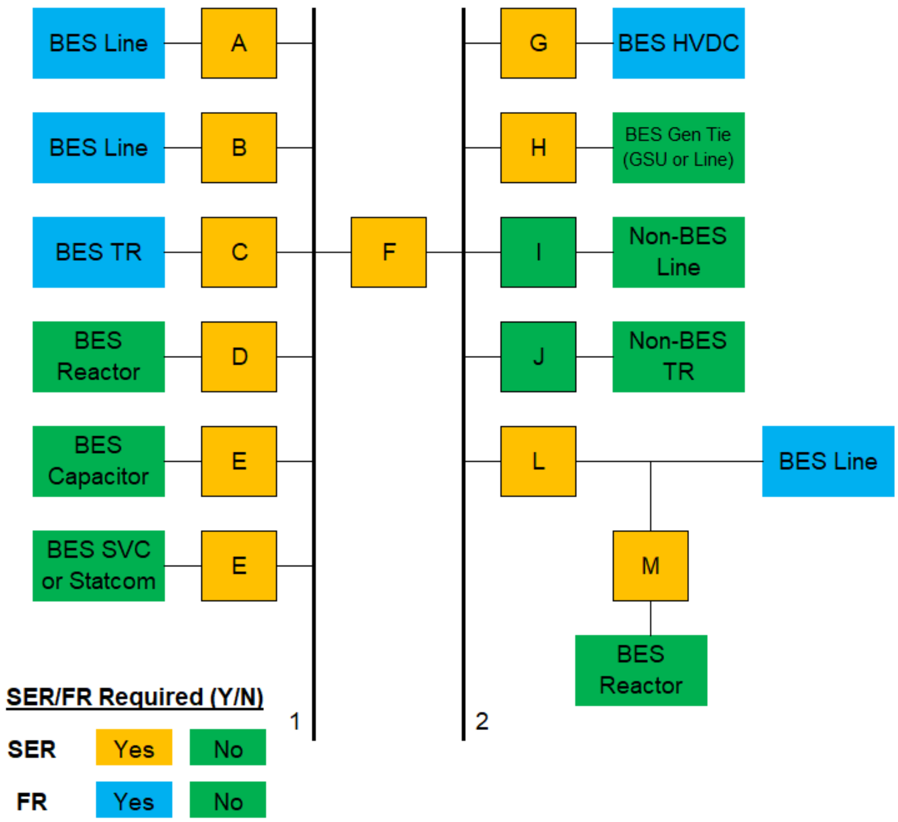

Figure 9: Straight BES Buses

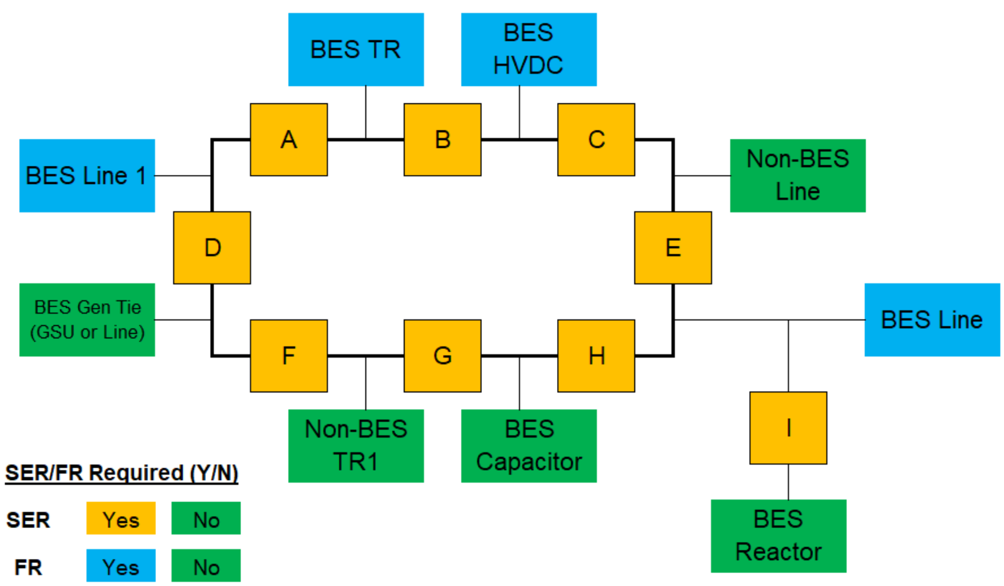

Figure 10: Ring BES Bus

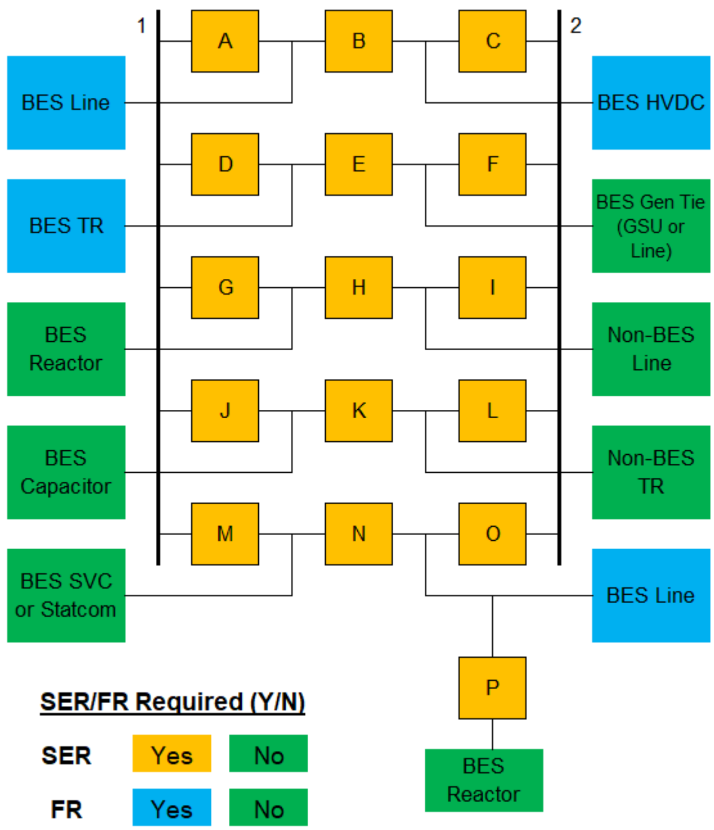

Figure 11: Breaker and Half BES Bus

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data, it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents. Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault, the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses

Rationale for Requirement R4

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30- contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of Protection System operations after a fault to determine if a Protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Rationale for Requirement R5

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data, as per Requirement R5, is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO’s, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

DDR data is used for wide-area Disturbance monitoring to determine the System’s electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System-wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means, and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes.

However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather, the drafting team believes this determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR, such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Rationale for Requirement R6

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-4 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-4 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three-phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Rationale for Requirement R7

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at eitherthe high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again, it must be emphasized that the data requirements for PRC-002-4 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement R8

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post- contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Rationale for Requirement R9

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Rationale for Requirement R10

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore, the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment.

Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of one millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement R11

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30 calendar days (or the granted extension time), subject to Part 11.2, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10 calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity, or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.2 specifies the maximum time frame of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.1 specifies that the minimum time period of 10 calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10 calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30 calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchrophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Rationale for Requirement R12

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90 calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90 calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System.

Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90 calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Technical Rationale for Reliability Standard TOP-001-6

April 2021

TOP-001-6 – Transmission Operations

Rationale

Rationale text from the development of TOP-001-3 in Project 2014-03 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 and Project 2016-01 pages.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its Transmission Operator Area. TOPs perform various analyses and studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances. Examples include:

- OPA;
- Real-time Assessments (RTA);
- Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and
- Analysis which may be specified in the RC's outage coordination process that leads the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

Rationale for Requirement R13:
The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator’s Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:
The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

FAC-011-4 R6 clarifies when an SOL exceedance is occurring and as such likely increases the number of SOL exceedances for some TOPs. This increased number of SOL exceedances could create an administrative burden on System Operators for entities that rely on operator logs as the primary form of evidence for compliance. This would be an unintended consequence of interaction between the new FAC-011-4 R6 and TOP-001-4 Requirement 14, which states, "Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment." This is because TOP-001-4 Requirement 14 treats all SOL exceedances equally and does not differentiate among them based on duration or risk to the BES.

Concerns were raised by drafting team members and observers as to the effect on Real-Time System Operators being required to log initiation of the Operating Plan for every SOL exceedance per TOP-001-4 R14, especially those which were considered short duration, low risk SOL exceedances that were actually successfully mitigated within a short-term time frame. This could distract System Operators to focus on compliance documentation during times when they should be fully committed to implementing the Operating Plan and mitigating the SOL exceedance.

The revised TOP-001-6 M14 addresses this concern by identifying examples of "other evidence" that can be utilized to support compliance which require less human intervention for capturing. Examples allowing TOPs to use other types of evidence such as system logs/records showing the SOL exceedance successfully mitigated in conjunction with Operating Plans is important because it clarifies that validation of successful SOL mitigation is the primary interest and focus of evidence. Successful SOL mitigation coupled with Operating Plans that have been prepared for utilization in the event of an SOL exceedance can demonstrate that the TOP initiated and implemented its Operating Plan. For example, providing outputs of State Estimator and/or Real-Time Contingency Analysis (with start time and end time of SOL exceedances) in conjunction with Operating Plans that outline roles and responsibilities between TOP and its RC in eliminating SOL exceedances, would document resolution of the SOL exceedance as well as the Operating Plan in use for the resolution. These should be sufficient evidence for Requirement R14 while reducing or eliminating the administrative burden on System Operators to manually generate compliance evidence via logging or recording actions.

These Operating Plans may be strengthened with clarifying information such as automatically switched or scheduled switching operating strategies/processes that describe how automatic control actions correct SOL exceedances, which can prevent unnecessary collection of evidence. Use of operating policies as a part of Operating Plan may include specific control actions (such as taking a transmission line out of service or disconnecting a generator for a low risk high voltage SOL exceedance) on post-contingent basis, and may be utilized if it was included into operating protocols and confirmed in real-time. Other records, such as binding constraint logs, could document the actions taken to alleviate certain thermal SOL exceedances through the role of redispatch algorithms that generate revised dispatch setpoints for generators to alleviate the constraint.

Finally, further evidence may include some of the operating protocols shared between a TOP and RC as part of the Operating Plan; they may support instances where the TOP and RC agree to each take certain predetermined actions and or share information. For example, if an RC had to initiate manual redispatch with a Generator Operator when a TOP initiated binding constraint was insufficient (e.g. not fast enough), the TOP may utilize RC-provided logs as evidence of compliance if the RC and TOP have agreed to share such information. Additionally, use of these joint operating protocols as evidence recognizes situations and operating conditions when the RC initiates and implements an Operating Plan on behalf of TOP, per these joint operating protocols. In these situations, pre-specified actions taken by the TOP and RC and agreed upon in their joint operating protocols could allow the RC's binding constraint logs to be used by the TOP as evidence of compliance.

Rationale for Requirement R15:
Clarity of what is determined to be an SOL exceedance in new revision FAC-011-4 may increase, in some instances, the number of SOL exceedances and thus the communications that are required consistent with TOP-001-4 Requirement R15 (as well as IRO-008-2 Requirement R5 and R6) which states, "Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded."

Concerns were raised as to the effect on System Operators being required to communicate every SOL exceedance, especially those which were considered short duration, low risk, SOL exceedances (e.g. less than 15 min, 30 min). This could be a significant increase for entities that historically performed RTAs more frequent than the required 30 minutes. Proposed FAC-011-4 R7 addresses this concern by requiring the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure consistency within an RC's area between the RC and its TOPs.

The use of the terminology "in accordance with its SOL methodology, aligns the notification requirements of TOP-001-5 R15 with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. For example, the SOL methodology could state that an RC and TOP sharing with each other real time monitoring and RTCA output information could provide clear communication and indications of when SOL exceedances appear and are mitigated in real time, meeting the requirements of the standard. This communication could range from simply RC and TOP sharing via ICCP output from the real time monitoring and RTCA output to operator to operator communications.

Rationale for Requirements R16 and R17:
In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:
Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):
[Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R21:
The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for Requirements R22 and R23:
[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Balancing Authority's (BA) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R23 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the BA's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R24:
The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for R25:
Requirement R25 was added to align the Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis activities with the RC’s SOL methodology. This will ensure that methods and frameworks that surround what is required in the SOL methodology are utilized during these activities (e.g. contingencies utilized, stability criteria, performance framework, etc.) in determining SOL exceedances.