« *Technical Rationale for Reliability Standard* » (Justification technique) (FAC-011-4, FAC-014-3, IRO-008-3 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.

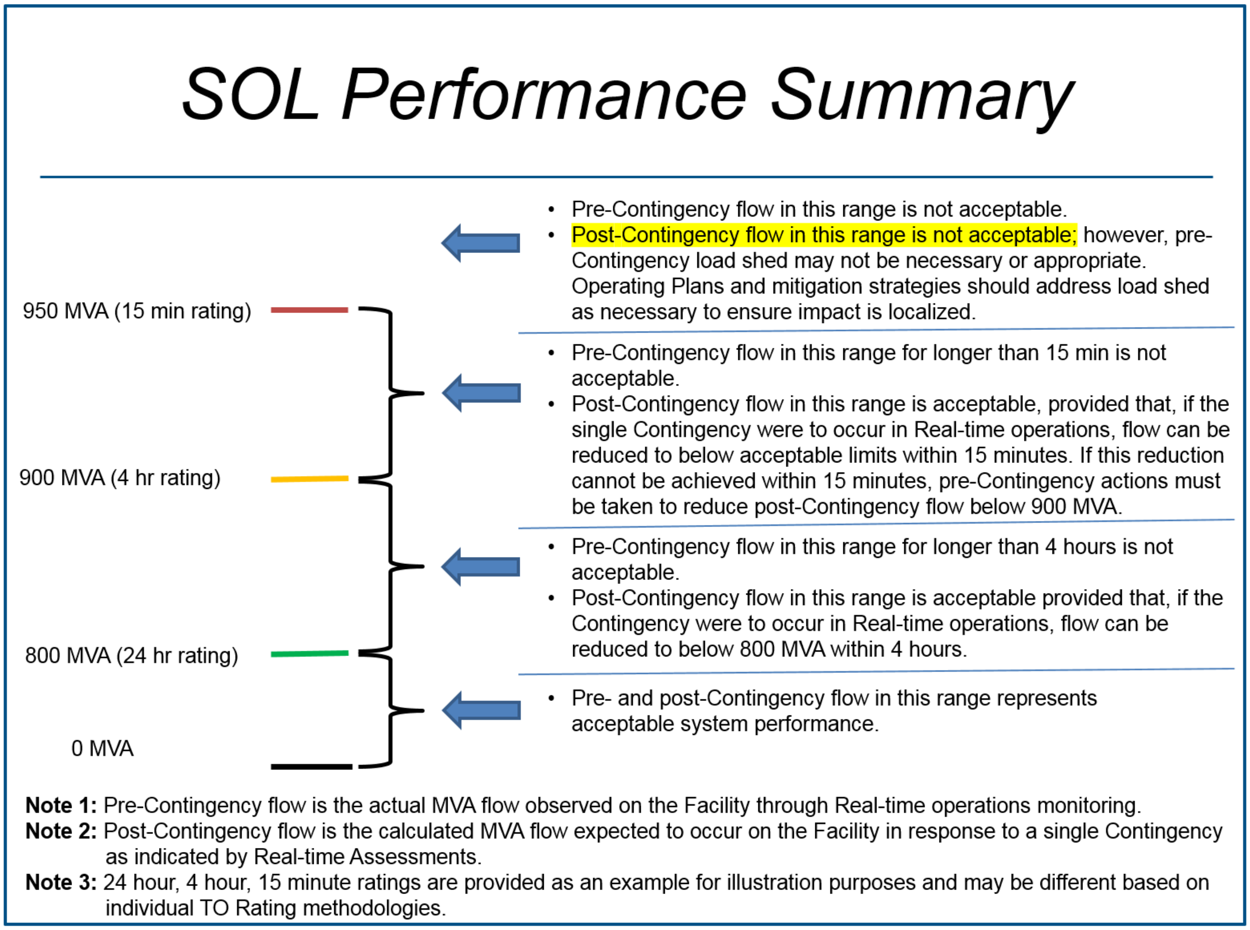

Figure 1 of the NERC SOL Whitepaper

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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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 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.