<u>TOP/IRO Standards - Items for SDT Discussion from FERC NOPR (*Updated August 2014*)</u>

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards
145 FERC ¶ 61,158 (2014)

<u>Plan and Operate within all System Operating Limits</u>

Para 42: Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area.

Para 43: … affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11

<u>SDT Consideration:</u>

The Project 2014-03 SDT has changed the proposed requirements to include all SOLs. This resolves the first issue (analyze and operate within all SOLs) identified in paragraph 42. See proposed TOP-001-3, Requirements R14 and R15.

> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
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> Proposed TOP-001-3, Requirement R15: Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. In addition, proposed IRO-008-2, Requirements R1, R3, R6, R7, and R8 have been revised to include System Operating Limits. This resolves the second issue (only those identified… internal to its area) in paragraph 42.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Proposed IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Proposed IRO-008-2, Requirement R4: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Proposed IRO-008-2, Requirement R6: Each Reliability Coordinator shall notify 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.

A remaining issue would be where SOLs overlap Transmission Operator Areas as pointed out in the Technical Conferences. If the SOL overlaps Transmission Operator Areas, then the Transmission Operator would coordinate with its Reliability Coordinator with its wide-area view to cover that SOL. This topic is already covered by the SOL methodology defined in approved FAC-011-2, Requirement R1, and the requirement to coordinate operations between Reliability

Coordinators as shown in proposed IRO-014-3, Requirement R1. See also proposed IRO-002-4, Requirement R4.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
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> Proposed IRO-014-3, Requirement R1: Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
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> Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Para 52: During deteriorating system conditions, an SOL can rapidly degrade into an IROL. … NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 53: We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 54: We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.

<u>SDT consideration:</u>

The original project teams (Projects 2006-06 and 2007-03) established the concept of operating within IROL T_v. T_v is always less than or equal to 30 minutes so the issue for IROLs is covered.

The Project 2014-03 SDT has agreed to the addition of all SOLs as explained above (see paragraph 43 response). Requirements for handling SOLs within a specified timeframe are covered under approved FAC-008-3, Requirement R6 where each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. These Facility Ratings are part of the data required in the data specifications mandated in proposed TOP-003-3, Requirement R1. The Project 2014-03 SDT agrees the Transmission Operator shall have operational or mitigation plans for all SOLs that consider time-based rating methodology. See proposed TOP-001-3, Requirement R14. The SDT agrees that the Transmission Operator shall develop and coordinate these mitigation plans with its Reliability Coordinator – see proposed TOP-002-4, Requirement R6. Such plans shall also include steps that ensure BES performance consistent with approved FAC-011-2 Requirement R2, including provisions for pre-Contingency load shed to avoid voltage instability, uncontrolled Cascading, or separation.

Approved FAC-008-3, Requirement R6: Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.

Proposed TOP-003-3, Requirement R1: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Proposed TOP-001-3, Requirement R14: 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.

Proposed TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.

Approved FAC-011-2, Requirement R2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance

Para 55: Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. … we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

SDT consideration:

The Project 2014-03 SDT views the time horizon item as an issue that involves analysis tools in a Real-time environment. The intent of the original SDTs was that any aspect of analysis tools would be covered in Project 2009-02. For various reasons, that project has been delayed. Therefore the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 to the SOL and Transmission Operator Area – see proposed TOP-001-3, Requirement R13. In addition, the SDT has added proposed TOP-001-3, Requirement R16 concerning operator control of monitoring and analysis capability outages.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
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> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities

As part of this process, the definition of Real-time Assessment has been revised to provide greater clarity as to the intent of the defined term.

> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

The Project 2014-03 SDT believes that approved EOP-008-1, Requirement R1, Part 1.6.2 assures that any solution to the analysis issue in the preceding paragraphs is adequately covered as to redundancy and back-up concerns.

> Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

In addition, due to concerns raised in the Technical Conferences, the Project 2014-03 SDT has provided guidance as to when an entity has exceeded a limit. This guidance is provided in a white paper that will be shown in the Associated Documents (Section F) of proposed TOP-001-3.

Para 56: Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon.

SDT consideration:

See responses above to previous cited paragraphs on SOLs. .

System Models, Monitoring and Tools

Para 60: Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

SDT consideration:

With respect to monitoring, the Project 2014-03 SDT has adapted approved IRO-003-2, Requirement R1 for the Transmission Operator and Balancing Authority Areas. See proposed TOP-001-3, Requirements R10 & R11.

Proposed TOP-001-3, Requirement R10: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems and

10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

> Proposed TOP-001-3, Requirement R11: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions

With respect to analysis, the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13.

> Proposed TOP-001-3, Requirement R13: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Para 61: The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02. Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

<u>SDT consideration:</u>

See previous response.

<u>Compliance with Reliability Directives</u>

Para 64: The currently-effective TOP Reliability Standards use "reliability directive," which, as an undefined term, does not appear to be limited to a specific set of circumstances. … In contrast, application of the proposed definition of "Reliability Directive" appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements).

<u>SDT consideration:</u>

The Project 2014-03 SDT is replacing the term 'reliability directive' with the defined term 'Operating Instruction' throughout the proposed standards. The proposal to use a new defined term 'Reliability Directive' is no longer being considered.

Para 65: NERC's TOP and IRO petitions do not explain the proposed, defined term "Reliability Directive," or why compliance with a transmission operator's directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

SDT consideration:

See previous response for paragraph 64.

Para 66: … NERC has not explained or justified its request for approval of the revised definition.

SDT consideration:

See previous response for paragraph 64.

Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

Para 67: In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. ~~The p~~Proposed TOP-003-3 requires applicable entities to develop a data specification that covers its needs for monitoring and analysis purposes. There is no restriction on what voltage level or area that data can be pulled from. Proposed TOP-003-3, Requirement R5 shows a Transmission Operator being required to supply requested data to another Transmission Operator which clearly shows that a Transmission Operator can request and receive data from outside of its immediate area. The original SDTs have been clear in response to questions on this matter that they did not intend to place any restrictions on the type and location of data involved as long as the request was reliability based. However, to clear up any possible misconceptions, the Project 2014-03 SDT has amended proposed TOP-003-3, Requirement R1, Part 1.1 to explicitly specify that ~~sub-100 kV~~ non-BES data and external data should be part of the data specification for Transmission Operators. Similar requirements exist in proposed IRO-010-2 for the Reliability Coordinator.

> Proposed TOP-003-3, Requirement R1, Part 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
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> Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES

data and external network data, as deemed necessary by the Reliability Coordinator.

Concerns were raised during the Technical Conferences that proposed TOP-003-2 did not require that an entity actually use the data acquired in its monitoring and analysis functions. ~~The Project 2014-03 SDT discussed this concern and concluded that an explicit requirement to use the data was an unnecessary administrative concern.~~ The Project 2014-03 SDT believes that the qualifiers placed in proposed TOP-003-3, Requirement R1, Part 1.1 (shown above) citing that the data specified is to support Operational Planning Analysis, Real-time Monitoring, and Real-time Assessments indicate that the data is to be used and that no further action is required on that particular issue.

However, the question arises as to what non-BES data and external network data is required. Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R3, Part 3.4 states that the level of detail required in system models for determination of SOLs must be part of the Reliability Coordinator's methodology which will determine what, if any, non-BES data is needed. Approved FAC-011-2, Requirement R4, Part 4.3 then requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators who will follow the methodology in its work in determining SOLs. ~~These~~This combination of requirements will dictate what non-BES and external network data a Transmission Operator needs to acquire (if any).

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
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> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
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> Approved FAC-011-2, Requirement R3, Part 3.4: Level of detail of system models used to determine SOLs.
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> Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Para 68: In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…. The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.

SDT consideration:

See previous response for data (paragraph 67).

In addition, the Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address all aspects of outage coordination between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner.

Para 69: The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

SDT consideration:

See previous responses under this heading.

Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

Para 70: NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.

SDT consideration:

The Project 2014-03 SDT believes that the concept of stating an explicit requirement to operate to the most severe single Contingency is not necessary as the FAC standards require an entity to analyze and operate for all Contingencies and not just the most severe single Contingency. The definitions of Operational Planning Analysis and Real-time Assessment have been strengthened to clarify this point.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Para 73: NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency …

<u>SDT consideration:</u>

See previous response.

… to move quickly from an "unknown operating state" to within proven limits …

<u>SDT consideration:</u>

~~See previous responses for this heading.~~ <u>The Project 2014-03 SDT believes that there is always a set of limits in service and asserts that an operator, given a condition that has not been previously studied, is obligated to adhere to the set of limits in service at the time of the event. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined and what to do upon experiencing an SOL exceedance. The SDT believes that the situation has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to proposed TOP-001-3, Requirements R12 and R13 as well as the guidance provided on Operating Plans in proposed TOP-001-3, Section F.</u>

<u>Proposed TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.</u>

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed TOP-001-3, Section F: Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

… and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards.

SDT consideration:

The Project 2014-03 SDT agrees that a Transmission Operator needs to take appropriate action to mitigate the exceedance but does not agree to the inclusion of determining the 'cause' of the violation in Real-time. Real-time is not when to investigate or to do detailed analysis – but instead is the time to 'fix' the problem. Causes can be determined later and off-line. The Project 2014-03 SDT, as previously stated, has agreed to include the concept of Real-time Assessment for Transmission Operators. This assessment is believed to be sufficient in identifying 'cause' for operators in Real-time. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 74: In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.

SDT consideration:

The Project 2014-03 SDT does not feel that it is advocating a different approach as shown in the previous responses above.

> How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules?
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> SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation?

SDT consideration:

The Project 2014-03 SDT sees this item as having been addressed due to the commitments made above such as adding all SOLs to the standards and performing Real-time Assessments.

In addition, approved FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and Stability limits (including voltage) while demonstrating that the BES remains stable (transient, dynamic, and voltage) during pre-contingent (Requirement R2, Part 2.1) and post-contingent (Requirement R2, Part 2.2) conditions. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. Approved FAC-014-2, Requirement R5, Part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider and approved FAC-014-2, Requirement R5, Part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities.

> Approved FAC-011-2, Requirement R2, and Parts 2.1 and 2.2:
> The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
> 2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
> 2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be

operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Approved FAC-014-2, Requirement R5, Part 1: The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.

If so, is the difference significant for reliability purposes?

SDT consideration:

See previous response.

Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability?

SDT consideration:

Yes, industry operates to T_v for all IROLs which is 30 minutes or less. By definition, only IROLs can cause Cascading or instability.

Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the proposed rules allow doing so while the current rules do not?

SDT consideration:

The Project 2014-03 SDT does not see that any changes are being suggested that would change the way these situations are handled today.

Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

SDT consideration:

The SDT proposes to use approved IRO-008-1, Requirement R2 as the model for development for such capabilities for Transmission Operators as described above. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

SDT consideration:

Proposed TOP-001-3, Requirement R13 states that a Transmission Operator must perform a Real-time Assessment every 30 minutes. This is 'what' must be accomplished but doesn't explain 'how' it can be done. That is left to the applicable entity. Smaller entities are free to devise equal and effective methods to accomplish this task. The ERO Rules of Procedure also allow them to contract out services for performing such assessments as long as they retain the responsibility for the final result. To clarify this concept, the Project 2014-03

SDT has added language to the definition of Real-time Assessment on the topic of contracted services.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 75: With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

SDT consideration:

See response to paragraph 73 above.

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Approved EOP-008-1, Requirement R1, Part 1.6.2 covers ~~this~~the situation where backup or redundant capabilities are required.

Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

System Protection Coordination

Para 78: The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal. Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.

SDT consideration:

Project 2014-03 SDT is no longer revising PRC-001-1. Project 2007-06 is responsible for PRC-001-1 revisions.

Notification of Emergencies

Para 80: NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.

Para 81: Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

Para 82: While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion. … We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

SDT consideration:

The Project 2014-03 SDT has combined the previously proposed TOP-001-2, Requirements R3 & R5 into one requirement in proposed TOP-001-3, Requirement R8 that uses only actual and projected Emergency covering all time horizons.

Proposed TOP-001-3, Requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

Para 83: … NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. … In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

SDT consideration:

See previous response.

Primary Decision-Making Authority for Mitigation of IROLs/SOLs

Para 84: NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

Para 87: NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

SDT consideration:

The Reliability Coordinator has the responsibility for IROLs and the Transmission Operator has the responsibility for SOLs. This split in responsibilities is an important concept for the preservation of reliability within the BES and needs to be clear in the various standards and requirements. However, as discussed above, the Reliability Coordinator shall provide oversight on SOLs and assistance in mitigating SOLs as necessary.

See previous response to paragraph 43 on SOL overlap issues.

Planned Outage Coordination

Paragraph 90: The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.

SDT consideration:

The SDT has developed a new standard, IRO-017-1 Outage Coordination, to address the overall topic of outage coordination. In addition, the SDT has revised proposed IRO-014-2, Requirement R1, Part 1.4 to show that outage information must be made available and analyzed. Also, the Planning Coordinator and Transmission Planner have been added to proposed IRO-010-2 as applicable entities to ensure the sharing of planning information with the Reliability Coordinator.

> Proposed IRO-014-2, Requirement R1, Part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
>
> Proposed IRO-017-1, Requirement R1: Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall:
> Identify applicable roles and reporting responsibilities.
> 1.1.1 Development and communication of outage schedules.
> 1.1.2 Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).
> 1.2 Specify outage submission timing requirements.
> 1.3 Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.
> 1.4 Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.
>
> Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.
>
> Proposed IRO-017-1, Requirement R3: Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.
>
> Proposed IRO-017-1, Requirement R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Secure Network

Paragraphs 92 & 93: Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished “via a secure network.” According to NERC, the requirement to provide information via a “secure network” is now addressed in NERC Rules of Procedure, Section 1002 (Reliability Support Services). NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

SDT consideration:

The Project 2014-03 SDT understands the sensitivity around the concept of secure networks for transfer of data and has made appropriate changes to proposed TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3, to allow for the concept of security to be part of the mutually agreed upon data specification.

Proposed TOP-003-3, Requirement R5, Part 5.3: Mutually agreeable security protocol(s).

Proposed IRO-010-2, Requirement R3, Part 3.3: Mutually agreeable security protocol(s).

Reliability Coordinator Monitoring of SOLs

Paragraph 96: Although NERC’s petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC’s explanation that Reliability Standard IRO-002-2 Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

SDT consideration:

The Project 2014-03 SDT believes that monitoring SOLs is intrinsic to the duties of a Reliability Coordinator as spelled out in Functional Model v5. However, to provide clarity, the Project 2014-03 SDT has provided explicit requirement language to address the need for monitoring SOLs at the Reliability Coordinator level. See proposed IRO-002-4, Requirement R4. As pointed out starting in paragraph 84 of the NOPR, only one entity can be responsible for SOLs and that is the Transmission Operator.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. These requirements will dictate what external data a Reliability Coordinator needs to acquire to effectively monitor SOLs.

Proposed IRO-010-2, Requirement R1, Parts 1.1 – 1.2 show additions to the data specification concept to clarify that external data, ~~sub-100 kV~~non-BES data, and applicable relay data are included.

> Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

> Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

> Proposed IRO-010-2, Requirement R1, Part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.