Reliability Coordinator Area
System Operating Limit Methodology
Western Interconnection
8300EXT00132

Revision 2.0

MAINTAINED BY
SPP Operations Staff

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REVISIONS

Revision	Date	Description of Modification
0.1	11/30/2018	Initial draft version
0.2	1/8/2019	Second draft version
0.3	1/16/2019	Initial Creation with approval by the CMSTF
0.4	2/20/2019	Revisions as a result of WRWG discussions
1.0	3/19/2019	Initial Creation with approval and implementation approved by the WRWG
1.1	7/9/2019	Corrected omission of NERC Reliability Standard FAC-011 required language by adding section 3.5. Approved by WRWG on 7/17/2019.
2.0	4/1/2024	Updates made to comply with FAC-011-4 and FAC-014-3

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1. Introduction

This document is SPP's 'System Operating Limits Methodology for the Operations Horizon' for the Western Interconnection. This document establishes the methodology for use in the SPP RC Area - Western Interconnection for developing System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) for use in the Operations Horizon pursuant to NERC Reliability Standards FAC-011 and FAC-014.

All requirements for establishing SOLs and IROLs are contained in the body of this document. An additional document titled 'Appendices to Reliability Coordinator Area System Operating Limit Methodology Western Interconnect' provides best practices or background information but does not contain additional requirements.

TOPs and the RC will continually assess and evaluate projected system conditions within the Operations Horizon with the objective of ensuring acceptable system performance in real-time. These assessments are performed in an iterative fashion, typically beginning as part of seasonal studies, followed by assessments performed as part of the IRO-017-1 Outage Coordination Process, followed by Operational Planning Analyses (OPAs), and ultimately concluding with Real-time Assessments (RTAs). Accordingly, these studies use anticipated transmission system configuration, generation dispatch, and load levels, which are expected to improve in accuracy through the iterative assessments as Real-time approaches.

1.1 Applicability of this Methodology

This document applies to TOPs within the SPP RC Area in the Western Interconnection as well as the SPP RC itself for developing SOLs and IROLs used in the Operations Horizon:

Operations Horizon: *A rolling 12-month period starting at Real-time (now) through the last hour of the twelfth month into the future.*

The concepts in this SOL Methodology apply to all sub-horizons within the Operations Horizon, such as, seasonal studies, outage coordination studies, OPAs, and RTAs.

1.2 Use of Capitalized Terms

When a term from the North American Electric Reliability Corporation (NERC) Glossary of Terms is used in this document, the term will be capitalized. Other capitalized terms are defined in this document.

1.3 SOL versus TTC

WECC paths do not have single uniquely monitored SOL(s) unless the WECC path is associated with an established transient or voltage Stability Limit.

Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. While it is expected that TTCs respect pre- and post-Contingency reliability limitations associated with Facility Ratings, System Voltage Limits, and Stability limits, the determination and communication of TTC is outside the scope of SPP's SOL Methodology - Western Interconnection.

Exceeding a TTC value does not constitute an SOL exceedance. However, if a TOP so chooses, the TOP may utilize TTC (and Transfer Capability concepts) as part of an Operating Plan.

2. Selection of Applicable Contingencies

2.1 Definitions of Terms Used in Section

A. Credibility – the quality of being plausible (believable) and likely (probable).

B. Credible Multiple Contingency (MC) – a MC whose Credibility is considered sufficiently high to warrant protecting against.

C. Observable System Conditions – known, observable or foreseeable conditions. The conditions could be external such as a brush fire or severe weather (e.g., flooding, icing, tornados), or internal such as a breaker with a low-gas alarm which poses an elevated risk that the breaker may not operate as anticipated to clear a fault. Note: Impact to the BES is not an observable system condition.

D. Always Credible MC – a MC that has static Credibility (as a Credible MC) through all phases of the Operations Horizon (seasonal and other special studies, outage coordination assessments, Operational Planning Analyses, and Real-time Assessments). This MC's Credibility is not a function of Observable System Conditions. Note: The TOP's list of Always Credible MC's is determined by an internal TOP risk assessment (i.e., likelihood and impact).

E. Conditionally Credible MC – a MC whose Credibility is a function of Observable System Conditions. Conditionally Credible MCs are only Credible when the Observable System Conditions are present. When the Observable System Conditions are not present, the

MC is not Credible. Note: Conditionally Credible MCs are a function of Observable System Conditions that increase the likelihood of the MC only, not a function of BES impact.

2.2 Contingencies Applicable for Operations Horizon TOP Assessments

It may be appropriate that a subset of contingencies be evaluated due to the nature of the study such as stability analysis. Contingencies will be selected in the vicinity of the study area in order to provide meaningful results based on previous analysis results, TOP input, and engineering judgement.

2.2.1 Single Contingencies Internal to the TOP Area

The single Contingencies that shall be studied for assessments (seasonal studies, special studies, outage coordination studies, OPAs, RTAs) within the Operations Horizon include the following[1]:

A. Single-line-to-ground (SLG) or three-phase Fault (whichever is more severe[2]), with Normal Clearing, on any Faulted BES generator, line, transformer or shunt device.

B. Loss of any BES generator, line, transformer, or shunt device without a Fault

C. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system

[1] The Contingencies identified in items (a) through (c) are the minimum Contingencies that must be studied but are not necessarily the only Contingencies that are studied.
[2] It is up to the TOP to determine when a SLG is an appropriate Fault type to study.

2.2.2 Credible MCs Internal to the TOP Area

The Credible MCs that shall be studied for assessments within the Operations Horizon include the following two types[3]:

A. Always Credible MCs

B. Conditionally Credible MCs

Note that N-1-1 Contingency types (corresponding to P3 and P6 Contingencies in TPL-001-4, Table 1) are not included for consideration as Credible MCs within the Operations Horizon. A specific combination of two overlapping single Contingencies, by itself, is not an issue of Credibility or non-Credibility. Rather, it is a matter of knowing which combination of overlapping single Contingencies to be prepared for based on known issues with those specific combinations. Such operational risks are expected to be addressed through Operating Plans as these risks are identified.

Reference Appendix D for more information about how N-1-1 studies may be used to determine IROLs.

2.2.3 Contingencies External to the TOP Area

TOPs are responsible for determining any single Contingencies and Credible MCs external to the TOP Area that are known to impact the TOP Area or system under study. These external contingencies could reside in a TOP area outside the SPP RC area. At the request of a TOP, the SPP RC can facilitate coordination with a neighboring RC where necessary. If the SPP RC or any other RC identifies any single Contingencies and Credible MCs external to the TOP Area that are known to impact the TOP Area or system under study, the SPP RC will provide such information to the affected SPP RC area TOPs. TOPs are responsible for determining the external modeling necessary to support the evaluation of Contingencies identified by both the TOP and RC.

[3] Credible MCs in the Operations Horizon shall be, at a minimum, studied as SLG. Alternatively, a TOP may study Credible MCs as three-phase Faults.

2.3 Requirements for Determining Always Credible MCs

A. When developing the list of Always Credible MCs for operations, TOPs shall perform an internal risk assessment (i.e., likelihood and impact) to determine the MCs internal to their TOP Area that shall be considered Always Credible for operations based on factors and issues that are unique to their TOP Area. Appendix B contains possible approaches for internal risk assessment.

B. It is the primary responsibility of the TOP in whose TOP Area the MC Facilities reside to determine MC Credibility. However, because the RC is the highest reliability authority in its RC Area, the RC has the authority to determine an MC's Credibility that supersedes a TOP's designation. Should the RC exercise such authority, the RC shall perform an evaluation of historical MC performance and a risk assessment based on the factors and issues driving the RC to supersede the TOP's determination, and the RC shall share this information with impacted TOPs.

C. When an MC terminates in different TOP Areas, the TOPs are expected to collaborate and agree on the MC Credibility.

D. If an impacted TOP challenges or disagrees with a TOP's decision or rationale for a MC's Credibility, or if TOPs cannot agree on the Credibility of the MC that impacts their TOP Area, the TOPs involved are expected to coordinate with the RC to reach a resolution as described in Section 12 of this methodology.

2.4 Always Credible MC Communication

A. TOPs shall review their list of Always Credible MCs annually at a minimum, and document changes to the list of Always Credible MCs. TOPs must use the template posted to SPP RC's website titled "Always Credible Multiple Contingencies TEMPLATE.xlsx" to communicate TOP-identified Always Credible MCs. TOPs shall post the populated template for its TOP Area in the "Always Credible MCs" folder on the secure SPP RC site. If the TOP does not have any Always Credible MCs, the TOP shall post a "null list" with a note in the spreadsheet indicating that the TOP has not identified any Always Credible MCs for their TOP Area. TOPs shall submit the completed spreadsheet with the filename "Always Credible Multiple Contingencies – TOPxyz.xlsx".

B. When a TOP posts an updated list to the "Always Credible MCs" folder, the TOP must move prior versions to the Archive folder and fill out the "Revision History" tab in the updated list.

C. Any known changes to the list of Always Credible MCs shall be posted six months[4] before the start of each operating season. Note that the template requires each Always Credible MC to be accompanied by a rationale for its Credibility.

2.5 Addressing Conditionally Credible MCs

A. Conditionally Credible MCs are not required to be pre-identified or included along with the list of Always Credible MCs. However, if the TOP pre-identifies any Conditionally Credible MCs and creates a standing Operating Plan for that MC, the TOP shall provide that Operating Plan to the RC for awareness purposes. If such pre-identified Operating Plans impact or involve other TOPs, then the Operating Plan shall be developed in collaboration with the impacted/involved TOPs and communicated to those TOPs.

B. Conditionally Credible MCs become credible when the Observable System Conditions are present. The TOP in whose TOP Area the MC Facilities reside is responsible for determining when a Conditionally Credible MC becomes credible and when it ceases to be credible.

C. When a Conditionally Credible MC becomes credible, the TOP in whose TOP Area the MC Facilities reside must notify the RC and other TOPs known or expected to be impacted by the MC. This notification shall include at a minimum: MC description, MC type, impacted TOPs, the Observable system Conditions, projected duration of the MC's Conditional Credibility and any Operating Plans that may be required as a result of the MC.

D. When a Conditionally Credible MC is no longer credible, the TOP in whose TOP Area the MC Facilities reside must notify the RC and other TOPs identified in 2.5 B that the MC is no longer credible.

E. The TOP in whose TOP Area the MC Facilities reside must collaborate with the RC and impacted TOPs to create and implement an Operating Plan (or to implement a pre-determined Operating Plan) to address the Conditionally Credible MC. If agreement/resolution cannot be achieved through collaboration, the RC has the authority to make the final determination of the Operating Plan(s). In its final determination, the RC is expected to coordinate with the impacted TOPs.

[4] Study plans are finalized six months before the start of the operating season in the Recommended Seasonal Operations Planning Coordination Process. However, it is acceptable for changes to the list of Always Credible MCs to be made with less than six months' notice when the change becomes known less six months ahead of the operating season.

F. Impacted TOPs and the RC are expected to include the Conditionally Credible MCs in their respective studies while the Conditionally Credible MC is credible.

G. When Conditionally Credible MCs become credible and the MC impacts multiple TOPs, the SPP RC will collaborate with impacted entities and neighboring RCs to ensure that the MC is being addressed in a coordinated manner.

2.6 Requirements for the Treatment of Credible MCs

A. The RC must include Always Credible MCs in RC assessments (seasonal studies, special studies, outage coordination studies, OPAs, RTAs). The RC must include Conditionally Credible MCs in RC assessments while the MC is credible.

B. TOPs must include their own Always Credible MCs in TOP assessments (seasonal studies, special studies, outage coordination studies, OPAs, RTAs). The TOP must include its own Conditionally Credible MCs in TOP assessments while the MC is credible.

C. If TOP seasonal studies, special studies, outage coordination studies or OPAs fail to verify acceptable system performance for an Always Credible or applicable Conditionally Credible MC, the TOP and all impacted TOPs must collaborate and develop an Operating Plan(s) to provide acceptable performance for the MC. If agreement/resolution cannot be achieved through collaboration, the RC has the authority to make the final determination of the Operating Plan(s). In its final determination, the RC is expected to coordinate with all impacted TOPs. The RC may determine that an IROL needs to be established to address the reliability risk. Reference the IROL Establishment section of this SOL Methodology for more information. Similarly, if TOP RTAs fail to verify acceptable system performance for a credible MC, the TOP must implement an Operating Plan to mitigate the unacceptable system performance for the credible MC.

D. SPP RC includes credible MCs in RC assessments (both Always Credible MCs and any applicable Conditionally Credible MCs that are communicated to the RC) and evaluates those MCs. SPP RC applies the Cascading test as described in the section entitled Instability, Cascading, Uncontrolled Separation and IROLs when determining potential Cascading. SPP RC does not evaluate credible MCs against more stringent performance requirements. If SPP RC’s special studies, outage coordination studies or OPAs fail to verify acceptable system performance for a credible MC, an Operating Plan must be developed to provide acceptable performance for the credible MC. Similarly, if SPP RC’s RTAs fail to verify acceptable system performance for a credible MC, an Operating Plan must be implemented to mitigate the unacceptable system performance for the credible MC. SPP RC does not include non-credible MCs in RC assessments.

E. If an MC is not declared as Always Credible by the TOP in whose TOP Area the MC Facilities reside and is not posted on the SPP RC website, then the MC is not required to be honored in the Operations Horizon (seasonal studies, special studies, outage coordination assessments, OPAs, RTAs). Note that Conditionally Credible MCs that become credible in the Operations Horizon are addressed separately (see Section 2.5 above).

F. Note that not all Contingencies within a TOP Area (single Contingencies or credible MCs) are expected to be included in certain types of analyses. For example, time-domain, PV/QV and transfer studies are not conducive to analyzing as many Contingencies as can be done in steady-state Contingency analyses performed as part of a power flow. For studies such as time-domain analyses and PV/QV analyses, TOPs and the RC are expected to include those Contingencies that are the most severe to the situation based on experience, engineering judgment and historical analysis.

G. If a TOP determines that an MC in its TOP Area is non-credible, yet a neighboring/impacted TOP desires to include that non-credible MC in its assessments, the neighboring/impacted TOP may do so; however, the neighboring/impacted TOP cannot require other TOPs to address reliability issues related to the non-credible MC and cannot require any other TOP to honor that MC in operations or in the development or implementation of Operating Plans.

H. The RC shall consider any of the MCs that have been determined by its PC to result in Stability Limits.

3. Acceptable System Performance

In the SPP RC Area, the BES is expected to be operated such that acceptable system performance is being achieved in both the pre- and post-Contingency state. This section describes acceptable system performance for the pre- and post-Contingency state.

In the event that reliability studies performed by the RC and TOPs do not agree on the severity of an identified reliability issue, the most limiting (severe) study result will be acted upon until the cause of the difference can be determined.

It is not the intent of this SOL Methodology to require more stringent BES performance criteria than that stipulated in the prevailing NERC Transmission Planning (TPL) Reliability Standards and WECC TPL criteria; however, this SOL Methodology may prescribe specific performance criteria where the corresponding performance criteria in planning is non-specific.

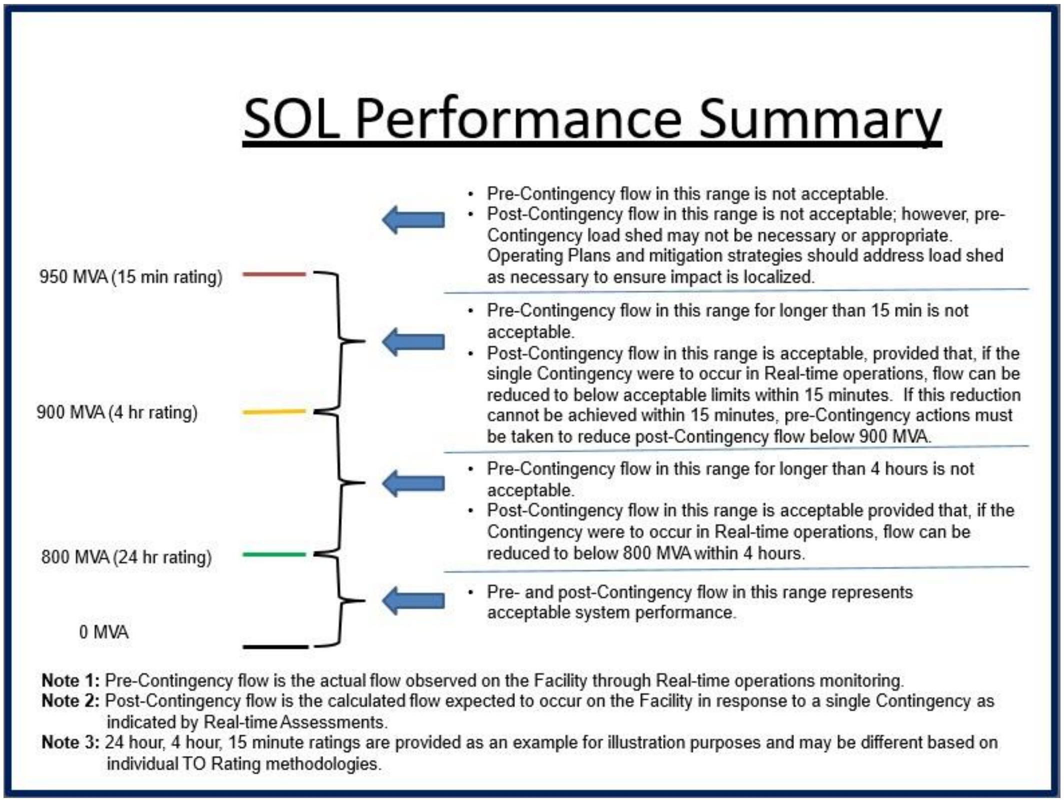


Figure 1 - SOL Performance Summary for Facility Ratings provides an example of acceptable pre- and post-Contingency performance for a sample set of Facility Ratings. The Facility Ratings shown in the example are selected for illustration purposes only.

3.1 Pre-Contingency

Acceptable system performance for the pre-Contingency state in the Operations Horizon is characterized by the following:

A. The BES shall demonstrate transient, dynamic and voltage Stability.

B. All Facilities shall be within their normal Facility Ratings within the specified duration of their Facility Rating (Refer to Figure 1 – SOL Performance Summary for Facility Ratingsabove.)

C. All Facilities shall be within their normal System Voltage Limits.

D. All Facilities shall be within their Stability Limits.

3.2 Post-Contingency – Single Contingencies

Acceptable system performance for the post-Contingency state for single Contingencies in the Operations Horizon is characterized by the following:

A. The BES shall demonstrate transient, dynamic and voltage Stability.

B. All Facilities shall be within their emergency Facility Ratings within the specified duration of their Facility Rating. (Refer to Figure 1 – SOL Performance Summary for Facility Ratings above.)

C. All Facilities shall be within their emergency System Voltage Limits.

D. All Facilities shall be within their Stability Limits.

E. Cascading or uncontrolled separation shall not occur.

3.3 Post-Contingency – Credible Multiple Contingencies

Acceptable system performance for the post-Contingency state for Credible MCs in the Operations Horizon shall not result in any of the following:

A. Instability

B. Cascading

C. Uncontrolled separation

3.4 Acceptable System Response

In determining the system's response to single Contingencies and Credible MCs, the following actions shall be acceptable:

A. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the faulted Facility or by the affected area.

B. Interruption of other network customers:

   a. Only if the system has already been adjusted, or is being adjusted, following at least one prior unplanned outage, or

   b. If the Real-time operating conditions are more adverse than anticipated in the corresponding studies.

[5] Note that these pre- and post-Contingency performance requirements are applicable to BES Facilities.

C. System reconfiguration through manual or automatic control or protection actions]. Adequate time must be allowed for manual reconfiguration actions.

3.5 Preparation for Next Contingency

To prepare for the next Contingency, system adjustments may be made, including changes to generation, and the transmission system topology.

4. SOL Exceedance

Actual and potential SOL exceedances occur when the acceptable system performance requirements as described in Section 3 of this document are not being met in seasonal studies, special studies, outage studies, OPAs or RTAs. Should it be determined that these criteria cannot be met, the exceedance shall be mitigated as soon as possible with no intentional delay in coordination with the RC. Mitigation techniques may include the use of interface/cutplane through the Congestion Management process, implementation of other TOP or RC developed Operating Plans, or any combination as required up to, and including load shedding. Pre-contingent load shed may not be appropriate for localized issues; however, plans should be in place and ready for use should the contingency occur. Planned manual load shedding is acceptable only after all other available System adjustment have been made This SOL Methodology considers an SOL exceedance to be a condition characterized by any of the following:

A. Actual/pre-Contingency flow on a Facility is above the Normal Rating.

B. Calculated post-Contingency flow on a Facility is above the highest Emergency Rating.

C. Actual/pre-Contingency bus voltage is outside normal System Voltage Limits.

D. Calculated post-Contingency bus voltage is outside emergency System Voltage Limits.

E. Operating parameters indicate a Contingency could result in instability.

4.1 Prioritization in Communicating SOL Exceedances

Real-time operators in the SPP RC area are constantly monitoring and performing Real-time Assessments in order to identify and mitigate SOL Exceedances. While it is important to coordinate when mitigating SOL Exceedances, it is equally important to prioritize the necessary communication when system operators are addressing multiple SOL Exceedances. The communication timeframes can be divided into two distinct groups based on expected occurrence frequency and risk level:

- Less frequent, higher risk: 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 as soon as possible and within 15 minutes of validated identification.

- More frequent, lower risk: Post-contingency SOL exceedances of Facility Ratings and System Voltage limits and pre-contingency Normal Maximum System Voltage Limits must be communicated within 30 minutes, if not resolved beforehand.

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). The provisions in the following table 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. Additionally, certain SOL Exceedance types may slide up or down the list based on exceedance magnitude or other considerations specific to the situation. The Communication Timeframe starts at the first time instance that the SOL exceedance is identified. The Communication Timeframe refers to the SOL exceedance identification; It does not require that an SOL exceedance is resolved in the specified timeframe.

Table 1 – SOL Exceedance Communication Timeframes

Priority	SOL Exceedance Type	Communication Timeframe	Associate Risk
Highest	IROL exceedances	15 minutes	Interconnection Reliability
	Post Contingency SOL exceedance or unsolved contingency with validated risk of instability, cascade, and/or uncontrolled separation	15 minutes	Interconnection Reliability

	SOL exceedance of stability limit	15 minutes	Localized Reliability
	Pre-Contingency SOL exceedance of Facility Ratings - Emergency	15 minutes	Imminent Equipment Damage or Degradation
	Pre-Contingency SOL exceedance of Facility Ratings - Normal	15 minutes	Imminent Equipment Damage or Degradation
	Pre-Contingency SOL exceedance of minimum System Voltage Limit - Normal	15 minutes	Imminent Equipment Damage or Degradation
	Pre-Contingency SOL exceedance of maximum System Voltage Limit - Normal	30 minutes if not resolved	Potential Equipment Damage or Degradation
	Post-Contingency SOL exceedance of Facility Ratings - Emergency	30 minutes if not resolved	Potential Equipment Damage or Degradation
Lowest	Post-Contingency SOL exceedance of System Voltage Limits - Emergency	30 minutes if not resolved	Potential Equipment Damage or Degradation

5. Allowed Uses of Automatic Mitigation Schemes

This section describes applicable mitigation schemes that automatically initiate mitigation actions in response to system conditions or Contingency events. (note that the use of UFLS Programs and UVLS Programs are not allowed in the establishment of stability limits).

5.1 Allowed Use of Automatic Mitigation Schemes in the Operations Horizon

The following items describe the allowed use of automatic mitigation schemes in the Operations Horizon, including both non-load-shed automatic schemes and load-shed automatic schemes:

A. If a TOP relies upon an automatic scheme for providing acceptable performance for single Contingencies or credible MCs, then the actions of the automatic scheme must be modeled in assessment tools or otherwise included in the TOP's analysis and the RC's analysis as applicable.

B. If at any time OPAs or other prior analyses indicate that the automatic scheme either fails to mitigate the reliability issue, potentially causes other reliability issues or could result in a more significant reliability risk, or if the automatic scheme is expected to be unavailable, the TOP must develop an Operating Plan in coordination with impacted TOPs and the RC, that contains pre-Contingency mitigation actions to address the reliability issue.

C. If at any time RTAs indicate that the automatic scheme either fails to mitigate the reliability issue, potentially causes other reliability issues or could result in a more significant reliability risk, or if the automatic scheme is unavailable, the TOP must initiate an Operating Plan in coordination with impacted TOPs and the RC, to take pre-Contingency mitigation actions to address the reliability issue.

D. Automatic schemes that have a single point of failure may not be utilized to prevent instability, Cascading or uncontrolled separation from occurring in response to single Contingencies or credible MCs. If any TOP seeks an exception, the TOP shall coordinate with the RC and request to be granted an exception until the necessary redundancies can be put in place and the automatic scheme classification is updated per the applicable standard or regional criteria. Exceptions may be made only for conditions that would otherwise require pre-Contingency load shedding. If operational situations arise where an automatic scheme that has a single point of failure must be relied upon to avoid pre-Contingency load shedding, such conditions must be coordinated and approved for use by the RC.

E. If an automatic scheme is relied upon to prevent instability, Cascading or uncontrolled separation in the transient or post-transient timeframe, the TOP studies must assess those timeframes to ensure that the automatic action occurs in time to prevent instability, Cascading or uncontrolled separation.

F. Several automatic schemes are intended and designed to address certain non- credible MCs (including extreme event Contingencies). In the Operations Horizon, these schemes are allowed to be relied upon to meet their intended design objectives for those non-credible and extreme event Contingencies; however, this SOL Methodology does not require assessment of – and therefore, determination of acceptable performance for – non-credible and extreme event Contingencies in the Operations Horizon.

5.2 Requirements Specific to Non-Load-Shed Automatic Schemes

Non-load-shed schemes include those that do not shed load as part of the mitigation action of that scheme. Examples of such schemes include generation drop schemes and transmission reconfiguration schemes.

A. Non-load-shed automatic schemes are not as restricted in their use as are load-shed automatic schemes. Accordingly, use of non-load-shed automatic schemes is allowed for the same conditions where the use of load-shed automatic schemes is allowed.

B. Non-load-shed schemes may be used as an acceptable automatic post-Contingency mitigation action, provided the general requirements listed in Items A-F in section 5.1 are met.

C. If a TOP intends to use a non-load-shed scheme in a manner for which the scheme was not intended and designed, and that intended use impacts other TOPs, the TOP must coordinate with impacted TOPs prior to reliance on that scheme.

5.3 Requirements Specific to Load-Shed Automatic Schemes

Load-shed schemes include any scheme that automatically sheds load in response to Contingency events. Such schemes include, but are not limited to, load-shed Remedial Action Schemes (RAS), Underfrequency Load Shedding (UFLS) schemes, Undervoltage Load Shedding (UVLS) schemes (including UVLS Programs) or other non-RAS schemes that automatically shed load in response to Contingency events.

In principle, the use of load-shed schemes in the Operations Horizon must take into consideration how the schemes are intended and designed to be utilized.

The following items describe the allowed use of load-shed schemes in the Operations Horizon:

A. Load-shed schemes shall be used and relied upon for the conditions/events for which the load-shed schemes are intentionally designed. There may be scenarios where it is appropriate to use or rely upon load-shed schemes to address Contingency events for which the load-shed scheme was not designed. Such instances should be minimized and should be thoroughly investigated and studied in the Operations Horizon to ensure that reliance on these schemes is reliable, prudent, consistent with sound engineering judgment and utility practice, and reflects appropriate risk management principles.

There may be conditions where the operational consequences of some load-shed schemes are such that TOPs in collaboration with the RC may choose to implement an Operating Plan that prevents the load-shed scheme from triggering for a given operating condition or Contingency event.

B. Some load-shed schemes are intended and designed to address certain credible MCs. If a load-shed scheme is intended and designed to address a specific credible MC, then the load-shed scheme is allowed to support economic operations and is allowed for consideration in the Operations Horizon, for:

   a. Assessing acceptable post-Contingency system performance for those MCs
   b. Determining whether or not a Stability Limit or an IROL needs to be established
   c. Calculating the value of the Stability Limit or the IROL, once it has been determined that there is a need to establish a Stability Limit or an IROL

C. Load-shed schemes may be relied upon and utilized in operations for single Contingencies if the scheme's impact where the TOP and RC coordinate in an operating plan in the local network area. However, load-shed schemes may not be relied upon or utilized in operations for single Contingencies to support economic operations[6].

6 The intent is to, if at all possible, limit reliance on such load-shed schemes to those that were designed and implemented per the allowances specified in Table 1 of TPL-001-4 for P1 Contingencies. While Table 1 TPL-001-4 indicates that Non-Consequential Load Loss is not allowed for single P1 Contingencies, the table includes footnote 12 which states, "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction." This footnote is intended to provide guidance but does not explicitly limit the amount of load that can be shed for a single contingency in the Operations Horizon.

D. There are times when a planned or forced outage of a Facility causes a MC in planning to become a single Contingency in operations[7]. When this type of scenario occurs for MCs for which a load-shed scheme was designed, the scheme can be relied upon and utilized in operations according to the following:

   a. When a forced or urgent[8] outage of a Facility causes a MC in planning to become a single Contingency in operations, the load-shed scheme can be relied upon to provide for acceptable system performance for the next single Contingency; however, System Operators shall take appropriate action up to, but not necessarily including, load shedding to (if at all possible), re- position the system in response to the forced or urgent outage such that the load-shed scheme is not required to provide for acceptable system performance for the next single Contingency[9]. In such conditions, Real-time studies, operations/engineering judgment and the operational consequences of the load-shed scheme should be considered in the overall risk management exercise when determining the appropriate course of action.

   b. When a planned outage of a Facility causes a MC in planning (for which a load-shed scheme was designed) to become a single Contingency in operations, TOPs shall develop an outage-specific Operating Plan to take appropriate action up to, but not including load shedding, to (if at all possible) pre-position the system such that the load-shed scheme is not required to provide for acceptable system performance for the next single Contingency for the duration of the planned outage. In planned outage scenarios, load-shed schemes are not allowed to be used to support economic operations for the next worst single Contingency. If at all possible, reliance on load-shed schemes for single Contingencies during planned outages should be limited to addressing local area Facility Rating exceedance issues.

[7] Example: A UVLS Program is designed in the planning horizon to prevent a common structure Contingency from resulting in instability. The structure carries two transmission lines. One of these two lines is removed from service on a planned or forced outage. From an operations perspective, the loss of the remaining line now represents a single Contingency during the period of time that the outage of the other line is in effect.
[8] Reference IRO-017-1 Outage Coordination Process for description of forced and urgent outage types.

[9] Appropriate actions may or may not include sectionalizing. If sectionalizing places more load at risk, then reliance on load-shed scheme is acceptable if the scheme was designed for the intended purpose.

Any planned outage that requires reliance on load-shed schemes to prevent instability, Cascading or uncontrolled separation during planned outages for the next single Contingency will be allowed only upon the express review and approval by the RC.

i. If at all possible, planned outages should be scheduled for a time when system conditions are such that a load-shed scheme is not necessary to provide for acceptable system performance for the next single Contingency during the planned outage.

ii. If it is not possible to schedule the planned outage as described above, and reliance on load-shed scheme cannot be avoided for the next worst single Contingency during the planned outage, the load-shed scheme action must be simulated and studied in TOP assessments and in RC assessments as applicable, and those studies must demonstrate that the load-shed scheme action provides for acceptable post-Contingency system performance.

6. Coordination Responsibilities

A. TOPs are expected to establish Facility Ratings based SOLs for use in the Operations Horizon in coordination pertinent adjacent TOPs.

B. TOPs are expected to establish System Voltage Limits in coordination with their respective TOs and with adjacent or impacted TOPs.

C. If TOPs are unable to reach a resolution on matters related to TOP-to-TOP collaboration and coordination, the most limiting value shall be utilized, and inform the SPP RC of the matter. The Dispute Resolution process may be utilized in parallel of resolving issues.

7. System Operating Limits

SOLs used in the Operations Horizon include Facility Ratings, System Voltage Limits and Stability limits. This section describes each of these three types of SOLs.

7.1 Facility Ratings

Facility Ratings are determined by the Transmission Owner (TO), in accordance with their respective Facility Rating methodology, considering such impacts as ambient temperatures, seasonal variances, normal/emergency operations, etc. Normal and Emergency Ratings are to be utilized when available, with acceptable timing requirements identified for all unique Emergency Ratings.

Emergency Facility Ratings with a time value less than 15 minutes can only be used if acceptable by both the TOP and the RC and documented in an approved Operating Plan.

7.1.1 SOLs Used in the SPP RC's Network Model

A. SPP RC's network model uses the ratings submitted by TOs and approved by TOPs through the Rating Submission Tool

B. SPP RC's analysis tools are also able to utilize dynamic Facility Ratings in Real-time operations. If a TOP uses dynamic Facility Ratings in Real-time tools, the TOP shall coordinate with SPP RC to facilitate SPP RC's implementation of those dynamic Facility Ratings in SPP RC's models for use in Real- time operations.

7.1.2 Communication of SOLs

A. TOPs are responsible for communicating to the RC any changes to the SOLs used in operations. This includes any temporary SOLs that may be implemented and changes to seasonal SOLs (e.g., when the TOP stops using summer seasonal SOLs and begins using fall seasonal SOLs).

B. Refer to SPP RDSWI for communication instructions.

C. SPP will consider external to SPP West RC footprint contingencies in establishing stability limits. If Stability limits impact more than one TOP or a neighboring RC then stability limits will be documented in operating guides or verbally for real time limits.

D. If TOPs are unable to reach a resolution on matters related to TOP-to-TOP collaboration and coordination, the most limiting value shall be utilized, and inform the SPP RC of the matter. The Dispute Resolution process may be utilized in parallel of resolving issues.

7.2 System Voltage Limits

This SOL Methodology defines System Voltage Limits as:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

It is important that the TOPs and the RC use the same set of System Voltage Limits for assessments within the Operations Horizon, including seasonal studies, outage coordination studies, special studies, OPAs and RTAs. While it is acceptable to use general or more stringent voltage limits to flag potential reliability issues, the established System Voltage Limits must ultimately be used for assessments within the Operations Horizon[10].

Operating within Low System Voltage Limits ensures that the buses across the BES have adequate voltage to support reliable operations of the BES.

Operating within High System Voltage Limits ensures that the system does not operate at unacceptably high voltage levels, and that the equipment connected to the bus is not subjected to voltages that exceed the equipment voltage rating. When equipment is subjected to voltages that are higher than the equipment's voltage rating, the equipment may be damaged and may not function properly when called upon.

TOPs shall establish System Voltage Limits according to the following:

[10] Some entities might use generic (or more stringent) voltage limits that may exist in planning models that do not reflect the System Voltage Limits that are used in actual operations.

7.2.1 Establishing System Voltage Limits

A. TOPs are responsible for the establishment of System Voltage Limits for the BES substation buses that exist within their TOP Area. TOPs have flexibility to modify these limits as necessary based on actual or expected conditions within the bounds of the subsequent requirements listed below, provided the changes are justified for reliability and a technically sound rationale can be provided.

B. System Voltage Limits must respect voltage-based Facility Ratings.

C. System Voltage Limits are applied to BES substation buses excluding the following:

a. Line side series capacitor buses,

b. Line side series reactor buses,

c. Dedicated shunt capacitor buses,

d. Dedicated shunt reactor buses,

e. Metering buses, fictitious buses or other buses that model points of interconnection solely for measuring electrical quantities, and

f. Other buses specifically excluded by the TOP in whose TOP Area the buses reside, provided the exclusion is justified for reliability and is documented.

D. While it is expected that TOPs take steps to coordinate the development of System Voltage Limits as described in the Coordination Responsibilities section of this SOL Methodology, it is the specific responsibility of TOPs to agree on the System Voltage Limits for buses with facilities that connect to buses owned by adjacent TOPs. The System Voltage Limit at each bus shall reflect voltage-based Facility Ratings from each adjacent bus. If the TOPs cannot agree, the most limiting System Voltage Limits in kV will apply as a default. If this default poses an unacceptable restriction or a reliability issue for the interconnecting TOPs, the TOPs must collaborate with SPP RC to reach a resolution.

E. System Voltage Limits must enable reliable BES operations. If a TOP provides System Voltage Limits that SPP RC determines to be detrimental to the reliable operation of the BES, SPP RC may request a technical justification for the use of such limits and may assign different System Voltage Limits if it is more conservative.

F. System Voltage Limits must not exceed voltage limits identified in Nuclear Plant Interface Requirements.

G. Low System Voltage Limits must not be lower than a value that triggers operation of UVLS. For all BES substation buses without UVLS, the Low System Voltage limits shall not be lower than 0.8 pu[11].

H. Normal High System Voltage Limits must not exceed the voltage ratings of the connected equipment.

H. Emergency High System Voltage Limits must not exceed Protection Systems that trip BES Facilities in response to high voltages.

I. For any applicable substation bus, System Voltage Limits must include the following:

a. A Normal Low System Voltage Limit – the low voltage limit that is used and monitored for actual/pre-Contingency operations. An actual/pre-Contingency voltage below a Normal Low System Voltage Limit is an SOL exceedance and requires implementation of an Operating Plan to increase the actual/pre-Contingency voltage above the limit. SPP will use minus five percent of nominal voltage unless a more limiting criteria is provided by the TOP.

b. An Emergency Low System Voltage Limit – the low voltage limit that is used for emergency operations and is otherwise monitored for the post- Contingency state. A calculated post-Contingency voltage below an Emergency Low System Voltage Limit is an SOL exceedance and requires pre-Contingency action, to increase the post-Contingency voltage above the limit. SPP will use minus ten percent of nominal voltage unless a more limiting criteria is provided by the TOP.

[11] See Appendix C.3 for rationale of the minimum allowable Low System Voltage Limit.

c. A Normal High System Voltage Limit – the high voltage limit that, is used and monitored for actual/pre-Contingency operations. An actual/pre- Contingency voltage is above a Normal High System Voltage Limit is an SOL exceedance, and TOPs need to take action, to decrease the actual/pre-Contingency voltage below the limit. SPP will use plus five percent of nominal voltage unless a different criteria is provided by the TOP

An Emergency High System Voltage Limit –the high voltage limit that is used for emergency operations and is otherwise monitored for the post- Contingency state. Emergency High System Voltage Limits shall be established such that they are actionable by the TOP and RC for the calculated post- Contingency voltage above an Emergency High System Voltage Limit an SOL exceedance and requires implementation of an Operating Plan to reduce calculated post-Contingency voltage to within the limit. SPP will use plus ten percent of nominal voltage unless a different criteria is provided by the TOP.

Table 2 – System Voltage Limits Monitor and Study Summary

Normal High/Low	**Emergency High/Low**
Real-time: • Monitored in SCADA or State Estimation for actual exceedance	Real-time: • Monitored in SCADA or State Estimation for actual exceedance • Monitored in RTCA (or equivalent) for calculated post- Contingency exceedance
Study: • Monitored for pre- Contingency exceedance	Study: • Monitored for pre-Contingency exceedance • Monitored in Contingency Analysis for calculated post- Contingency exceedance

7.2.2 Communication of System Voltage Limits

A. TOPs shall review their System Voltage Limits annually at a minimum and document changes to their System Voltage Limits. TOPs must use the template posted to SPP RC's website titled "System Voltage Limits TEMPLATE.xlsx" to communicate their System Voltage Limits. TOPs shall post the populated template for its TOP Area in the "System Voltage Limits" folder on the secure SPP RC site. TOPs shall submit the completed spreadsheet with the filename "System Voltage Limits – TOPxyz.xlsx".

B. When a TOP posts an update to the "System Voltage Limits" folder, the TOP must request the RC to move prior versions to the Archive folder and fill out the "Revision History" tab in the updated System Voltage Limits.

C. Any known changes to the System Voltage Limits shall be posted six months before the start of each operating season. Note that the SPP RC requires each System Voltage Limit variance and exclusion to be accompanied by a supporting rationale.

D. The "System Voltage Limits TEMPLATE.xlsx" contains four worksheets: default, variances, exclusions, and revision history. The default worksheet describes default normal and emergency System Voltage Limits for each voltage class utilized in the TOP Area. The variances worksheet describes the variances, if any, from the default System Voltage Limits. If there are no variances from the default table, populate the variances template with a message indicating that there are no variances for your TOP Area. If there are any station buses that do not require System Voltage Limits, those buses must be listed in the exclusions worksheet along with a rationale for their exclusion. If there are no exclusions required for the TOP's Area, populate the exclusions template with a message indicating that there are no exclusions for your TOP Area. If applicable, TOPs must explicitly communicate System Voltage Limits at nuclear plants using the variances template.

7.3 Stability Limits

The TOPs shall establish stability-based SOLs based on the methods identified in the subsequent sections of the Methodology. Baseline offline studies shall be performed in an attempt to identify stability-based SOLs that either are the most limiting SOL for a given Facility, or have the potential to encroach on the most limiting SOL for a given Facility under alternate system configurations. Real-time applications may be utilized where feasible; however, it understood that capability is limited in this time horizon and that the limits themselves are mostly established offline. Adjustments to RC established SOL/IROLs shall be made closer to and including Real-time may be made closer to and including Real-time, as system conditions warrant such action.

The RC and TOP will coordinate when it is appropriate to use Stability limits established in prior studies, or whether expected system conditions warrant performing new studies to revise those Stability limits used in Real-time operations.

When interface/cutplane Stability limits are established, they should be established in a manner that most accurately and directly addresses the instability risk. For example, a Stability limit should be established on an interface/cutplane that most accurately and directly monitors the instability risk, which may not coincide with defined WECC paths. Neither historical presumptions/practices regarding system monitoring nor commercial/contractual arrangements should influence where Stability limits are established to most accurately and directly monitor for reliability.

Stability limits will be studied based on expected operating conditions. Contingencies identified to be pertinent will be included in the analysis. Additional system stressing will be performed which might include transfer analysis, different generation/load levels, and additional transmission outages.

The RC will use common criteria to identify stability limits unless the TOP identifies more a conservative criteria threshold. The SPP RC will communicate stability analysis results that violate criteria thresholds to TOPs in its RC footprint and affected neighboring RCs. In order to identify a stability limit the RC may use Long Term Planning, Ops Planning, or Real Time horizon models.

7.3.1 Transient Analysis Methodology

A. It is up to the TOP and/or the RC to determine if and what types of operational transient studies are required for a given season, planned outage or operational scenario. For example, if a TOP or the RC determines, based on experience, engineering judgment and knowledge of the system, that a planned transmission or generation outage might pose a risk of transient instability for the next worst single Contingency or credible MC, the TOP shall perform the appropriate transient analyses to identify those risks.

B. The RC will consider expected levels of transfers, load and generation dispatch, and System conditions including any changes to System topology such as Facility outages in RC assessments (seasonal studies, special studies, outage coordination studies, OPAs, RTAs) when applying performance criteria in 7.3.2.

C. The RC will use updated modeling that's includes monitored lists, contingency lists, and RAS from the EMS. Dynamic modeling from internal and external sources will utilize the most updated version available.

D. If an allowable RAS is relied upon to address a transient instability phenomenon, the transient studies must simulate the actions of these schemes to ensure that the schemes adequately address the reliability issues. Associated study reports or Operating Plans must include a description of the actions and timing of these schemes.

E. Transient studies must model applicable Facility outages that are planned for the period of the study and must use appropriate load levels.

F. Expected loading conditions shall be screened for the period under study to determine the conditions under which instabilities occur. The TOP and/or the RC may run studies on only those specific set of loading conditions under which instabilities occur for subsequent studies.

G. Single Contingencies shall be simulated as the more severe of single line-to-ground Faults or three-phase Faults as determined by the TOP or RC. The more severe Faults will be simulated:

   a. At no more than 10 percent from each point of connection with bus; or

   b. The most severe of the high or low side of an autotransformer.

H. The Fault duration applied shall be based on the total known Fault clearing times or as specified in the corresponding planning studies for the applicable voltage level. For credible MC events, the appropriate clearing times must be modeled.

I. Transient studies must extend for at least 10 seconds following the initiating event or longer if swings are not damped.

J. The dynamics parameter file used for transient studies in all phases of assessments in the Operations Horizon (seasonal studies, special studies, outage coordination studies, OPAs and RTAs) shall be based upon the approved WECC dynamics file for the applicable season or other modeling that may be more updated.

K. The buses monitored for transient system performance are determined based on engineering judgment.

L. The use of Underfrequency load shedding (UFLS) and Undervoltage Load Shedding (UVLS) programs will not be considered in establishing stability limits.

M. The RC and TOPs shall ensure transient studies have been performed to verify performance criteria in Section 7.3.2 has been met for all expected pre and post contingent operational scenarios utilizing those applicable contingencies identified in Section 2.2.

N. Methods utilizing worst case studies, most severe contingencies, and monitoring of critical or weakest parts of the system can be leveraged to ensure the most severe impacts to the BES are being identified.

7.3.2 Transient Analysis Performance Requirements

Table 3 – Transient System Performance Requirements

Transient System Performance	**Threshold**	
The system must demonstrate positive damping. The signals used generally include power angle, voltage and/or frequency. An example of damping ratio calculation is provided in Appendix A.	3% Damping SPPR1 of %17.2 SPPR5 of 61.1% (See section 7.3.5)	
The BES must remain transiently stable, and must not Cascade or experience uncontrolled separation as described in this SOL Methodology. System frequency in the interconnected system as a whole must not trigger UFLS. Any controlled islands formed must remain stable. No BES generating unit shall pull out of synchronism	YES	
Transient voltage or frequency dips and settling points shall not violate in magnitude and duration: 1. Known generator trip settings or if trip settings are unknown, generator ride-through capabilities as specified by PRC-024-2 Attachments 1 and 2 or its successor. 2. Under frequency generator tripping (UFLS) shall not be triggered 3. Nuclear plant interface requirements	Minimum: 0.70 p.u. 2.5 seconds after the fault Maximum: 1.2 p.u. after the fault	

	General Notes: 1. A generator being disconnected from the system by Fault clearing action or by a RAS is not considered losing synchronism. Additionally, small (<25 MW) non-BES generators that may trip are not considered as losing synchronism. 2. If known BES equipment trip settings are exceeded, the appropriate actions must be modeled in the simulations. For generators that the GO or NPIR has identified as not being able to meet the PRC-024-2 requirements, either the unit must be tripped, or the Point of Interconnection (POI) frequency verified against the unit established trip values and the appropriate action taken.

[12] A TOP can coordinate with the RC and impacted TOPs to allow a BES generating unit to pull out of synchronism for a specific Credible MC.

[13] A TOP can coordinate with the RC and impacted TOPs to allow generators to be tripped for a specific Credible MC.

7.3.3 Establishment of Transient Stability Limits

A. Transient Stability Limits are established to meet the transient system performance requirements in Table 2 – Transient System Performance Requirements.

B. Transient Stability limited SOLs can include margins. Operating Plans shall specify if a transient Stability limited SOL includes margin.

7.3.4 Steady State Voltage Stability Analysis Methodology

- SPP utilizes the EMS model for establishing, calculating and monitoring SOLs/IROLs in the operating horizons. These cases are updated periodically to reflect expected system topology changes based on reported facility outages or upgrades.
- Monitored scenarios will be identified using available reliability studies, real-time system information, outage schedules, and other relevant sources. During the different Operating Horizons, the pre- and post-contingency operating conditions being studied may require mitigation. The SPP RC and TOPs must determine and coordinate which Contingencies within the TOP areas are to be utilized for study in the operating horizon.
- If the TOP or the SPP RC determine that changes are required for a pre- or post-contingency operating condition, such changes shall be communicated to the affected entities. The SPP RC will coordinate with all applicable impacted TOPs or neighboring RCs.
- The use of proxy interface/cutplane limits for stability will be communicated in the same manner as other interface/cutplane limits and information.
- The SPP RC will perform a voltage stability assessment for identified areas and paths that have a reasonable potential to cause real-time and post-contingency voltage instability.
- A voltage stability limit more restrictive than an existing SOL will be identified as the revised SOL and communicated to affected entities prior to implementation in congestion management procedures.
    - The RC will coordinate with the impacted TOPs to establish necessary mitigations and Operating Plans.
- The SPP RC may identify and establish voltage stability limits based on the voltage stability assessment results and will coordinate the voltage stability limits with the affected TOP(s). Voltage stability limits may require development of new temporary interface/cutplanes.
- No BES bus, or non-BES bus as deemed necessary, shall exceed the threshold set by an identified point of steady-state voltage instability including applicable margins.

7.3.5 Steady-State Voltage Stability Analysis

- Voltage Stability Limits are SOLs and can become IROLs. Voltage Stability Limits are established using transient (for fast voltage collapse risks) and post-transient analysis techniques. Reference Figure 2 – Sample P-V Curve as an example of a MW power transfer approach to defining a voltage Stability Limit.
- Voltage Stability limited SOLs can include margins as defined in section 7.2.1 above. Operating Plans shall specify if a voltage Stability limited SOL includes margin.

Reference Figure 2 – Sample P-V Curve below for an example of a PV curve for determining voltage Stability Limits.

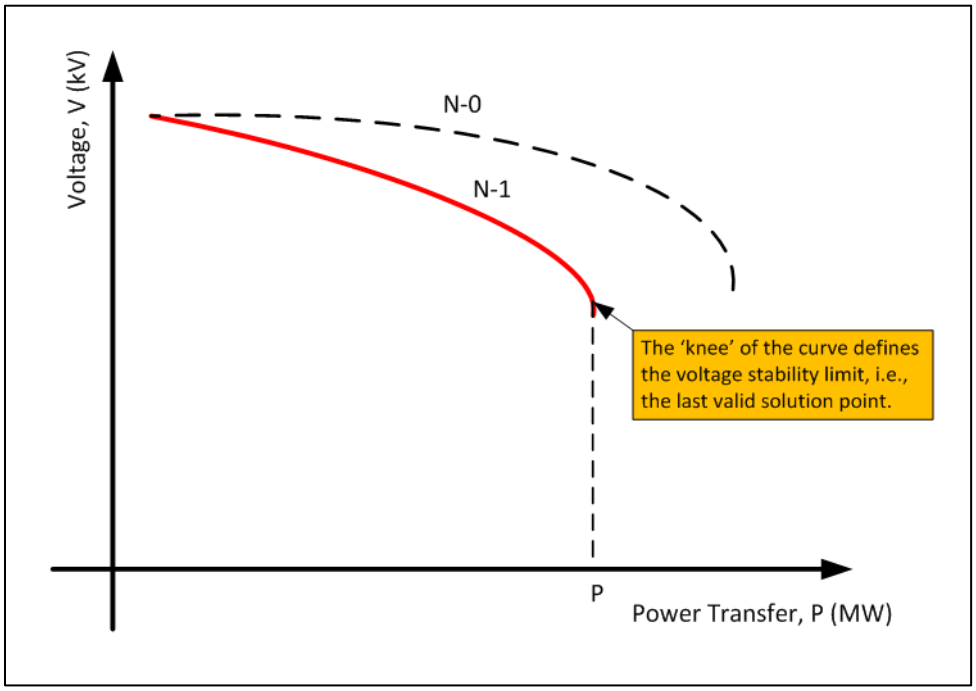


Figure 2 – Sample P-V Curve

7.3.6 System Damping

A. The system is typically considered to demonstrate acceptable positive damping if the damping ratio of the power system oscillations is 3% or greater.
B. SPP may perform additional simulations to validate damping results not meeting criteria in Real-time

Measuring damping is best performed a) after all significant automatic schemes have operated; and b) should measure damping over oscillations toward the end of the simulation rather than at the beginning of the simulation. As an example, a good trigger for measuring signal damping switched and the fault should be fully cleared.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

Successive Positive Peak Ratio One (SPPR1) must be less than or equal to 0. 828 where SPPR1 is calculated as follows:

Peak Rotor Angle of 2nd Positive Peak minus Minimum Value SPPR1

SPPR1 = --- ≤ 0.828

Peak Rotor Angle of 1st Positive Peak minus Minimum Value

Or Damping Factor % = (1 – SPPR1) x 100% ≥ 17.2%

Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.389 where SPPR5 is calculated as follows:

Peak Rotor Angle of 6th Positive Peak minus Minimum Value

SPPR5 = -- ≤ 0.389

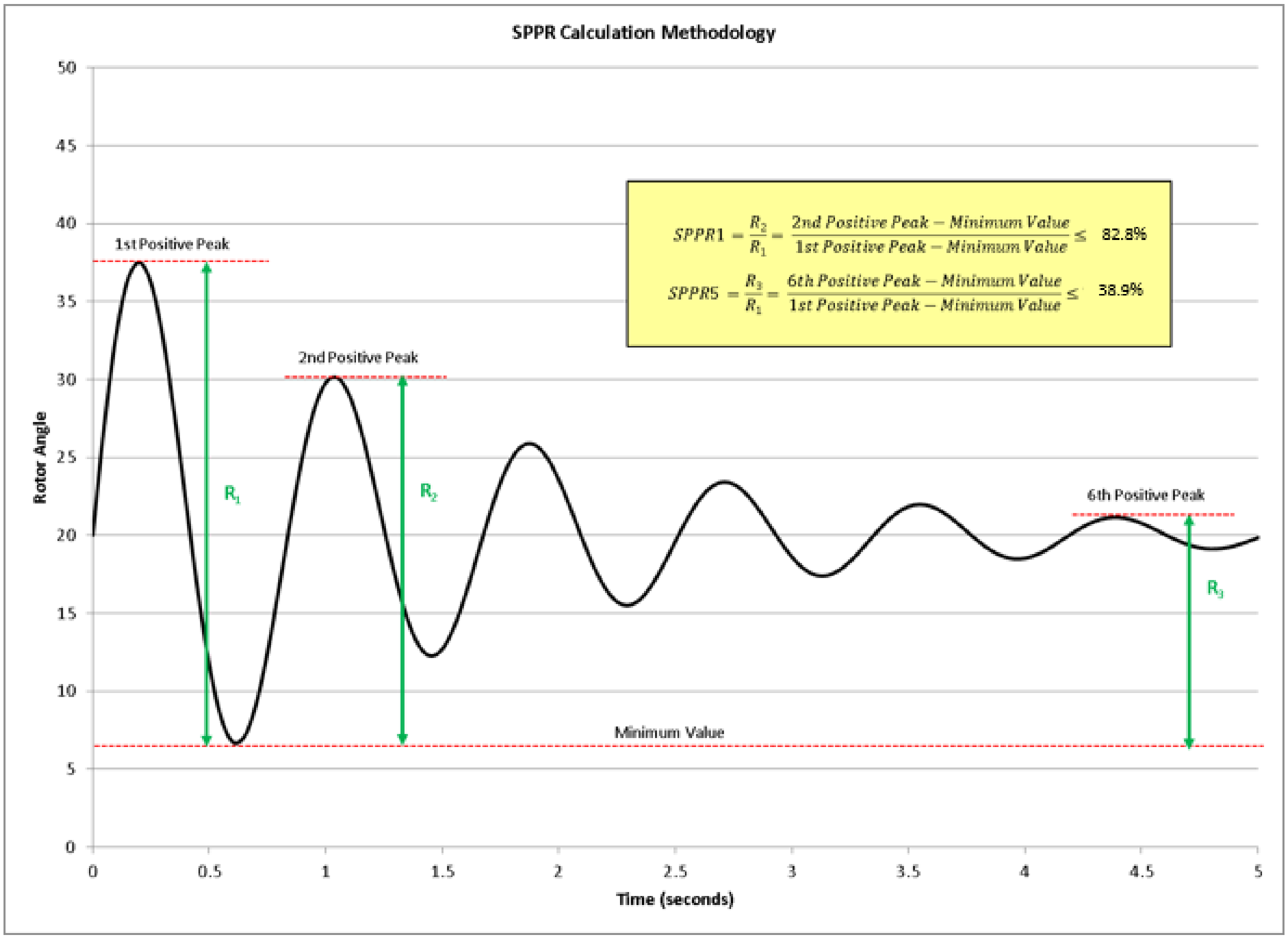
Peak Rotor Angle of 1st Positive Peak minus Minimum Value

-or-

Damping Factor % = (1 – SPPR5) x 100% ≥ 61.1%

The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio ≥ 0. 03



7.3.7 Angular Stability

A. Machine Rotor Angles shall exhibit well damped angular oscillations following a disturbance on the Bulk Electric System.

7.4 Communication of Transient and Voltage Stability Limits

A. When TOP studies indicate the presence of transient or voltage instability risks (whether contained or uncontained) for planned outages or expected system conditions, the TOP shall communicate the study results to SPP RC and to impacted TOPs for further coordination and review. This communication should occur in a timely manner to allow for proper coordination and preparation prior to Real-time operations.

B. TOPs shall communicate the following information for any identified transient or voltage Stability limit:

a. Instability Risk – a description of the instability risk that is addressed with the Stability limit

b. Contingencies – the Contingency(ies) that the Stability limit is protecting against

c. Outages – any transmission or generation outages associated with the Stability limit

d. Stability Limit Values – any pre-determined fixed value(s) for the Stability limit. Describe if the Stability limit established in real-time or calculated dynamically. In instances where there is no Stability Limit established to address the instability risk, RC still needs to know about the risk and how that risk is being addressed.

   i. Example, a forced transmission line outage has rendered a condition where a small load pocket is now served by two transmission lines instead of the usual three lines. A Contingency on either of the remaining two lines will result in local voltage collapse on the small load pocket. The only way of preventing the voltage collapse is to shed load pre-Contingency. The TOP and the RC agree not to shed load pre-Contingency to prevent the single Contingency from resulting in local, contained voltage collapse.

e. Monitoring Method – description of the method System Operators use for monitoring the Stability limit

f. Other Pertinent Information – any other pertinent operating conditions associated with the Stability limit, e.g., applicable to a certain season, a period of weeks/days/hours, certain loading conditions or other conditions, etc.

C. Transient or voltage Stability limit(s) identified as part of seasonal studies or special studies shall be communicated to SPP RC via PlanningAssessmentsSPPRC@spp.org. The subject line of the email shall clearly indicate that the communication contains an identified Stability limit.

D. Transient or voltage Stability limit(s) identified as part of outage studies or Operational Planning Analyses (OPA) studies shall be communicated to SPP RC via Outage Management System (OMS).

E. Transient or voltage Stability limit(s) identified as part of Real-time studies shall be communicated to SPP RC via phone.

F. Non-static transient or voltage Stability limit(s) are typically communicated to SPP RC via ICCP.

7.4.1 Post-Transient Analysis Methodology

The post-transient period is the timeframe after any initial swings and transient effects of a Contingency are over, but prior to AGC or operator actions. Post-transient analysis is performed through a governor power flow study.

A. The starting point of the analysis is the system condition with the Contingency modeled and taking into account the effects of allowable automatic actions as described in the Allowed Uses of Automatic Mitigation Schemes section of this SOL Methodology, e.g., UVLS, UFLS and RAS actions.

B. The Contingencies being studied shall be run with the area interchange controls and phase shifters controls disabled. Tap-Changer Under Load (TCUL), shunt capacitors and Static Var Compensators (SVC) that are automatically controlled may be allowed to switch provided the automatic control settings are accurately modeled and the devices will switch within 20 seconds or less[14]. Generators and SVCs shall be set to regulate the terminal bus voltage unless reactive droop compensation is explicitly modeled or SVC control signals are received from a remote bus.

C. Loss of generation shall be accounted for in the power flow by scaling up the generation in the interconnected system, with Pmax limits imposed, excluding negative generators and negative loads. Any increase or decrease in generation shall be done on the weighted MW margin (up/down range) or the closest equivalent based on the program used. Alternatively, units may respond in proportion to the nameplate ratings. Base-loaded units must be blocked from responding.

[14] The 20 second reaction time for switchable reactive devices is to ensure coordination with generator Maximum Excitation Limiter (OEL) settings. Typical OEL's will begin to reduce a generator's reactive output to safe operating levels within a 20-second window. Reference IEEE Recommended Practice for Excitation System Models for Power System Stability Studies, IEEE Std. 421.5-2005 (Revision of IEEE Std. 421.5-1992), 2006, pp. 0_1–85

8. Instability, Cascading, Uncontrolled Separation and IROLs

8.1 Instability

An IROL, as defined by NERC, is an SOL that, if exceeded, could result in instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES.

However, there are many forms of instability, each with a wide spectrum of reliability impacts – from little to no impact, such as losing a single unit due to its own "instability," all the way to a major and devastating impact, such as losing a major portion of the BES.

It is recognized that not all types of instability pose the same degree of risk to the reliability of the BES. At the same time, it also is recognized that regardless of the type of instability, it is critical that studies/assessment determine how – or if – the instability will be contained, and to understand the impact that the instability may have on the BES.

Accordingly, transient or voltage instability that cannot be demonstrated through studies to be confined to a localized, contained area of the BES effectively has a critical impact on the operation of the Interconnection, and therefore warrants establishment of an IROL.

IROLs and risk management for local and contained instability and a possible process for determining acceptable levels of risk for IROL determination for a local area is described in Appendix D.

8.2 Uncontrolled Separation

Uncontrolled separation (which includes uncontrolled islanding) occurs when studies indicate that a Contingency is expected to result in rotor angle instability or to trigger relay action which causes the system to break apart into major islands in an unintended (non-deliberate) manner. The determination of uncontrolled separation takes into consideration transient instability phenomena and relay actions that cause islands to form.

It is recognized that transient instability may result in the loss of small pockets of generation and load, or radially connected subsystems that do not warrant establishment of an IROL. In such scenarios, the loss of a unit (or group of units) may have little to no impact on the reliable operation of the interconnected system.

Uncontrolled separation can be understood by comparing it to controlled separation as described in Appendix D.

8.3 Cascading

Cascading can occur when studies indicate that a Contingency results in severe loading on a Facility, triggering a chain reaction of Facility disconnections by relay action, equipment failure or forced immediate manual disconnection of the Facility (for example, due to line sag or public safety concerns). Per the definition, when Cascading occurs, the electric service interruption cannot be restrained from sequentially spreading beyond an area pre-determined by studies.

Instability can cause Cascading. When Cascading is a response to instability, the Cascading will be addressed via a Stability-related IROL.

Cascading test – If powerflow studies indicate that the successive tripping of Facilities stops before the case diverges, then by definition, the phenomenon is not considered to be Cascading, because the studies have effectively defined an "area predetermined by studies." However, if the system collapses during the Cascading test, the area cannot be "predetermined by studies," and therefore it is concluded that the extent of successive tripping of elements cannot be determined. When this is the case, an IROL is warranted.

8.3.1 Powerflow Cascading Test:

A. Run Contingency analysis and flag single Contingencies and credible MCs that result in post-Contingency loading in excess of the lower of:

   a. The Facility(ies)'s trip setting

   b. 115 percent of the highest Emergency Rating

B. For each flagged Contingency, open the contingent element(s) that cause(s) the post-Contingency loading and all consequent Facilities that overload in excess of (1) (a) or (b) above. Run powerflow without simulating any manual system adjustments.

C. Repeat step (2) for any newly overloaded Facility (ies) in excess of (1) (a) or (b) above. Continue with this process until no more Facilities are removed from service or until the powerflow solution diverges.

D. If the subsequent tripping of Facilities stops prior to case divergence, then it can be concluded that the area of impact is predetermined by studies, and thus Cascading does not occur. If the case diverges during the Cascading test using the 115 percent of the highest Emergency Rating, then further investigation into post-Contingency loading may occur (if time allows) before declaring that Cascading occurs.

9. IROL Establishment

IROLs are established to prevent instability, uncontrolled separation or Cascading for:

A. Single Contingencies

B. Credible MCs

Interconnection Reliability Operating Limits (IROLs) are a subset of the SOLs that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System.

IROLs are always pre-identified through RC assessments (seasonal studies, special studies, outage coordination studies, or OPAs). An IROL may be established when Instability, Uncontrolled Separation, and/or Cascading meet any of the following criteria:

- thermal overload in excess of 115% of the emergency rating of the monitored facility that creates a cascading event or, (pending relay setting confirmation by the TOP)
- valid diverged or valid non-converged contingency or
- causes the loss of 1000 MW or more of firm load or greater, or
- causes the pre- and/or post-contingent voltage of 5 or more BES buses to fall below 0.9 p.u., or
- causes the successive tripping of 5 or more BES Transmission and/or generating Facilities (no system adjustments allowed), or
- impacting more than one utility, or
- causes the formation of one or more stable or unstable islands

All affected TOPs and the RC can agree an event is localized (and not classified as an IROL), but it must be a unanimous consensus.

During unanticipated Real-time events where Real-time Assessments indicate that the system is at risk of instability, uncontrolled separation, or Cascading for the next single Contingency or credible MC, the RC is expected to bring the system to a secure state with the same sense of urgency as it would address an IROL utilizing the applicable Operating Plans.

The RC is responsible for declaring IROLs. TOPs are not responsible for declaring IROLs. However, both the RC and TOPs are responsible for communicating and collaborating with each other to address the risks when studies (seasonal studies, special studies, outage studies or OPAs) identify the potential for instability (whether contained or uncontained), Cascading or uncontrolled separation as described in this SOL Methodology.

In the event of an IROL violation, the Bulk Electric System is vulnerable to instability, uncontrolled separation, and/or widespread cascading outages. All efforts, up to and including shedding of firm load, shall be made to mitigate the IROL exceedance within the defined Tv timeframe. In order to be best prepared for this situation, SPP has created relief guides that will assist the Reliability Coordinator in the relief of any flowgate with an IROL.

IROL limits are only applicable in the forward direction of interface/cutplane unless specifically stated in an IROL relief guide.

9.1 Types of IROLs

Since IROLs are a subset of SOLs, the following provides a brief characterization of each type of IROL that if exceeded could lead to instability, uncontrolled separation or Cascading:

9.1.1 Transient Stability IROLs

Establish to prevent:

A. The loss of synchronism (from rotor angle instability or associated relay action) that results in subsequent uncontrolled tripping of BES Facilities (Cascading), or in uncontrolled separation as described in this SOL Methodology.

B. Widespread voltage collapse that occurs in the transient timeframe.

A transient Stability IROL is not warranted to prevent one or more units from losing synchronism and tripping offline, provided that studies demonstrate that the transmission system remains stable after the units are lost.

9.1.2 Voltage Stability IROLs

Establish to prevent:

A. An undeterminable area or a wide area of the BES experiencing voltage instability

B. Voltage instability that consequently leads to Cascading or uncontrolled separation

9.1.3 Facility Rating-Based IROLs

Establish to prevent:

A. Non-stability related Cascading due to excessive post-Contingency loading of Facilities.Cascading that consequently leads to instability or uncontrolled separation.

Appendix D contains additional information including possible IROL study methodologies and examples.

10. IROL T_V in the SPP RC Area

The IROL T_V in the SPP RC Area shall be less than or equal to 30 minutes. The default IROL T_V value is 30 minutes. However, shorter duration IROL T_V values may be established in coordination with the impacted TOPs based on relay/protection settings and other considerations.

11. SPP RC Roles and Responsibilities

11.1 Adherence to this SOL Methodology

The RC must ensure that SOLs and IROLs for its RC Area are established and that the SOLs and IROLs are consistent with its SOL Methodology. SPP RC performs the following functions to meet this requirement:

A. SPP RC ensures that Facilities in the network model, which is SPP RC's Energy Management System (EMS) model, are associated with the Facility Ratings as provided by TOPs, consistent with this SOL Methodology.

B. SPP RC performs a coordination and facilitation role in the seasonal planning process for its RC Area as needed. See Appendix E, Recommended Seasonal Operations Planning Coordination Process.

C. SPP RC has a predominant role in the IRO-017 Outage Coordination Process for the RC Area.

D. SPP RC ensures that buses in the network model are associated with the System Voltage Limits as provided by TOPs, consistent with this SOL Methodology.

E. SPP RC reviews the Stability limits provided by TOPs to ensure they are established consistent with this SOL Methodology. SPP RC will establish an IROL once criteria in section

9 is met.

F. SPP RC ensures RC System Operators and engineers have awareness of identified Stability limits and IROLs.

G. SPP RC performs Real-time monitoring and RTAs to determine SOL exceedances and to determine if the system has unexpectedly entered into a single Contingency or credible MC insecure state. If the system has unexpectedly entered into a single Contingency or credible MC insecure state, SPP RC mitigates this condition within 30 minutes per internal Operating Plans.

H. SPP RC's Real-time Contingency Analysis (RTCA) application provides indication of whether acceptable steady-state system performance is being achieved for the post-Contingency state given actual system conditions. SPP RC shall post its RTCA results in a format that is mutually agreed upon by the SPP RC and SPP RC Area TOPs.

I. SPP RC utilizes a real-time voltage stability analysis tool and communicates the results of this tool to impacted TOPs.

11.2 Dispute Resolution

11.2.1 Disputes Between Entities

The SPP RC shall make a final determination on the appropriate course of action if a dispute should arise between two or more entities in the SPP RC area in any situations pertaining to this methodology. The SPP RC will coordinate with neighboring RCs if a dispute on the application of applicable SOL Methodology(s) should arise between two or more entites in separate RC footprints.

11.2.2 Most Conservative Operating Approach (eg Most Limiting Element)

If in the application of this methodology, an operational situation should arise where two entities (BAs, TOPs, GOPs) do not agree on actions necessary to maintain reliability of the Bulk Electric System, the most conservative approach will be implemented until such time that additional study evidence can alleviate the dispute. The SPP RC will coordinate with neighboring RCs if entities in dispute reside in multiple RC footprints.

12. System Study Models

The SPP RC network model is the system model used to determine SOLs. The scope of the SPP RC network model shall meet requirements defined per NERC Reliability Standards..

While Facility Ratings and System Voltage Limits may not require a TOP study for their establishment, Stability limits are identified as a direct result of system studies. TOPs within the SPP RC Area generally use any of three study models for identifying instability risks and establishing Stability limits: their respective EMS models, SPP RC's network model, and off-line

models based on approved WECC operating base cases. Development of the WECC operating base cases is coordinated by the WECC Regional Entity. The cases for each season are approved by the WECC Regional Entity.

WECC operating base cases often require seasonal coordination between TOPs (typically through subregional study groups) to ensure the topology, ratings and dynamic files are updated. When this seasonal coordination is required for accurate development of SOLs, TOPs shall participate in the base case coordination to ensure their TOP Area is accurately modeled.

SPP RC uses both the Full Network Model and the WECC operating base cases when performing system studies. The Full Network Model consists of the entire Western Interconnection BES. While the model contains some detail for non-BES Facilities, such as lower voltage generation models and the sub-100 kV elements identified by the TOPs to impact the BES, much of the system at these lower transmission voltages is reduced to a mathematical equivalent. Loads served over radial lines are typically lumped at the delivery bus. The Full Network Model consists of transmission lines, transformers, circuit breakers and switches, reactive devices, generation units, step-up transformers, loads and other relevant electrical components.

Though the WECC operating base case is not a breaker-to-breaker model, it consists of similar information as mentioned above as well as additional details and modeling information necessary to perform dynamic and transient Stability studies.

TOPs and the RC shall use study models that include the entire SPP RC Area for establishing Stability limits. The study model must include any critical modeling details from other RC Areas that would impact the Facility(ies) under study. That said, it is acceptable to use models that equivalence portions of the SPP RC Area's full loop model, provided that doing so does not impede capturing interactions between the TOP Area and the external systems or vice versa.

13. RC Communication of SOL/IROL Information to Other Entities

SPP RC shall provide its SOL methodology to those entities that indicate a reliability-related need within 30 days of a request or prior to the effective date of the SOL methodology. These entities include:

- Adjacent Reliability Coordinators and Reliability Coordinators with a reliability-related need for those limits
- Transmission Operators within the SPP RC Area
- Transmission Planners within the SPP RC Area
- Transmission Service Providers within the SPP RC Area
- Planning Authorities/Planning Coordinators within the SPP RC Area

SPP RC provides SOLs and IROLs to those entities listed below that have provided a written request that includes a schedule for delivery of those limits. These entities include:

A. Adjacent Reliability Coordinators and Reliability Coordinators with a reliability-related need for those limits

B. Transmission Operators within the SPP RC Area

C. Transmission Planners within the SPP RC Area

D. Transmission Service Providers within the SPP RC Area

E. Planning Authorities/Planning Coordinators within the SPP RC Area

SPP RC provides the following supporting information for each IROL as part of the corresponding IROL Operating Procedure:

A. Identification and status information of the associated Facility (or group of Facilities) that is critical to the derivation of the IROL

B. The value of the IROL and its associated TV

C. The associated Contingency(ies)

D. The type of limitation represented by the IROL (e.g., voltage collapse, transient Stability)