

**System Operating Limit Methodology for**

**Planning and Operations Horizon**

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# 1. Purpose

NERC standard FAC-010-3 R1 requires that each Planning Authority (PA) “shall have a documented System Operating Limit (SOL) Methodology for use in developing SOLs within its Planning Authority Area” for the planning horizon. NERC standards FAC-011-3 R1 requires that each Reliability Coordinator (RC) “shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area” for the operations horizon. This document describes the methodology for determining the SOLs, and the subset of SOLs classified as Interconnection Reliability Operating Limits (IROLs), for the planning horizon and operations horizon within the ERCOT Interconnection [FAC-010-3 R1.1, R1.3; FAC-011-3 R1.1, R1.3]. This methodology also documents the communications with other interested and affected organizations [FAC-014-2 R5, R6].

This methodology is intended to address NERC Reliability Standard requirements and does not restrict any entity from applying more conservative or alternative means to determine SOLs as needed.

# 2. Definitions

Where a NERC defined term exists, it is used in this document for that purpose. ERCOT specific definitions are only added as needed. The NERC Glossary of Terms Used in Reliability Standards provides the following definitions:

***Automatic Mitigation Plan (AMP) [ERCOT specific definition]:***

*A set of pre-defined automatic actions to execute post-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating, excluding any set of automatic actions that constitute a Remedial Action Scheme. AMPs shall only include schemes which switch series reactors by monitoring quantities that are solely located at the same substation as the switched device. AMPs shall not include adjusting or tripping generation or Load shedding and shall not be implemented on Interconnection Reliability Operating Limits (IROLs).*

***Bulk Electric System (BES):***

|  |
| --- |
| *Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.*  *Inclusions:*   * *I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.* * *I2 – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:*   *a) Gross individual nameplate rating greater than 20 MVA. Or,*  *b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.*   * *I3 - Blackstart Resources identified in the Transmission Operator’s restoration plan.* * *I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above.*   *Thus, the facilities designated as BES are:*  *a) The individual resources, and*  *b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.*   * *I5 –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.*   *Exclusions:*   * *E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:*   *a) Only serves Load. Or,*  *b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,*  *c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).*  *Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.*  *Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.*   * *E2 - A generating unit or multiple generating units on the customer’s side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.* * *E3 - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN’s emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:*   *a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);*  *b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and*  *c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).*   * *E4 – Reactive Power devices installed for the sole benefit of a retail customer(s).*   *Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.* |

***Cascading:***

*The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.*

***Emergency Rating:***

*The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved[[1]](#footnote-2).*

***Facility:***

*A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)*

***Facility Rating:***

*The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.[[2]](#footnote-3)*

***Generic Transmission Constraint (GTC) [ERCOT specific definition]:***

*A transmission constraint made up of one or more grouped Transmission Elements that is used to constrain flow between geographic areas of ERCOT for the purpose of managing stability, voltage, and other constraints that cannot otherwise be modeled directly in ERCOT’s power flow and contingency analysis applications.*

***Interconnection Reliability Operating Limit (IROL):***

*A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.*

***Interconnection Reliability Operating Limit Tv (IROL Tv):***

*The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit’s Tv shall be less than or equal to 30 minutes.*

***Market Information System (MIS)[ERCOT specific definition]***

*An electronic communications interface established and maintained by ERCOT that provides a communications link to the public and to Market Participants, as a group or individually.*

***Normal Rating:***

*The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.*

***Operating Plan:***

*A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.*

***Remedial Action Scheme (RAS):***

*A scheme designed to detect predetermined ERCOT System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s) to maintain a secure system. RASs do not include under-frequency or under voltage Load shedding, the isolation of fault conditions, or out-of-step relaying (not designed as an integral part of an RAS). RASs shall not be implemented on Interconnection Reliability Operating Limits (IROLs). Additional criteria that are excluded from being classified as RAS are outlined in the Operating Guides. A RAS owner can be a TSP or Resource Entity.*

***System Operating Limit (SOL):***

*The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*

* + ***Facility Ratings (****Applicable pre- and post-Contingency equipment or facility ratings)*
  + ***Transient Stability Ratings*** *(Applicable pre- and post-Contingency Stability Limits)*
  + ***Voltage Stability Ratings*** *(Applicable pre- and post-Contingency Voltage Stability)*
  + ***System Voltage Limits*** *(Applicable pre- and post-Contingency Voltage Limits)*

# 3. SOL/IROL Determination Methodology

This methodology is applicable for determining SOLs/IROLs used in the planning horizon and operations horizon. Determination is made by assessing the reliability of the currently planned ERCOT transmission system for the planning horizon or the expected topology of the ERCOT transmission system for the operations horizon. The assessment is accomplished through steady-state power flow, voltage stability, and transient stability analysis.

SOLs in the planning horizon are the most limiting of the prescribed reliability criteria for a specified system configuration to ensure BES performance within the reliability criteria described in the NERC Transmission Planning Standard (TPL-001-4). SOLs in the operations horizon shall always equal Facility Ratings unless studies have established a more restrictive limit based on operational conditions. Facility Ratings determine the fundamental limits of transmission system equipment. An SOL shall not exceed the associated Facility Rating [FAC-010-3 R1.2, FAC-011-3 R1.2]. Other factors, such as a transient or voltage stability limit, may lead to an SOL that is more limiting than the Facility Rating.

The IROLs for the planning horizon and operations horizon relate to specific system configurations or defined system conditions (demand level, generation pattern, transfer amount, and Facility contingency conditions) for which instability, uncontrolled separation, or Cascading outages are projected to occur as described in Section 3 of this methodology.

## 3.1. Transmission Planner SOLs

Transmission Planners (TPs) provide SOLs to ERCOT ISO (the Planning Authority (PA)). SOLs provided include all known Facility Ratings, system voltage limits, any known special transfer limits, and any stability limits that the TP has derived[[3]](#footnote-4). In accordance with this methodology, the TPs will also identify any SOLs they believe qualify as IROLs, based on the criteria identified in Section 3.6 of this methodology. All limits provided to the PA by the TPs will be included in the analysis described in Section 3.4 of this methodology.

## 3.2. Transmission Operator SOLs

Facility owners, including Transmission Operators (TOPs) that own transmission facilities, shall provide all known information to ERCOT ISO regarding the following: Facility Ratings, system voltage limits, any special transfer limits, and any stability limits. ERCOT ISO shall establish SOLs and IROLs, based on the information provided by the Facility owners, Transmission Operators and ERCOT ISO’s analysis described in Section 3 of this methodology. Transmission Operators shall notify ERCOT ISO of known system conditions that may affect SOLs and IROLs.

## 3.3. Steady-State System Voltage Limits

The system voltage limits provided to ERCOT ISO are utilized in the studies identified in Section 3 of this document. These system voltage limits are considered SOLs when they are the most limiting of prescribed reliability criteria in the Planning Horizon or the most restrictive limit based on operational conditions in the Operations Horizon.

### 3.3.1 Planning Steady-State System Voltage Limits

The following voltage ranges are considered to be the default steady-state system voltage limits in ERCOT:

(1) 0.95 per unit to 1.05 per unit in the pre-contingency state (and with all facilities in service in the planning horizon)

(2) 0.90 per unit to 1.05 per unit in the post-contingency state (following the occurrence of any “operating condition” or “contingency” or “event,” where appropriate)

If Facility owners have identified alternate planning steady-state system voltage limits for their facilities, the alternate limits will be provided for inclusion in the ERCOT Steady State Working Group (SSWG) model.

### 3.3.2 Operations Steady-state System Voltage Limits

The following voltage ranges are considered to be the default steady-state system voltage limits in ERCOT for Operations purposes:

(1) 0.95 per unit to 1.05 per unit in the pre-contingency state

(2) 0.90 per unit to 1.10[[4]](#footnote-5) per unit in the post-contingency state.

If a Facility owner has communicated to ERCOT ISO alternate values, then the Facility owner’s specified limits (e.g. a nuclear plant; Under Voltage Load Shedding (UVLS) set points) will be considered the steady-state system voltage limits for their Facilities. If ERCOT, or a neighboring Facility owner, determines that alternate values that are less restrictive than the default limits above create coordination and or operational concerns, the Facility owner may be asked to provide more restrictive limits to address such concerns.

A TOP may operate its portion of the ERCOT Interconnection utilizing different steady-state system voltage limits but must communicate those steady-state system voltage limits to ERCOT ISO[[5]](#footnote-6). When these system voltage limits are the most restrictive limit based on operational conditions within an assessment, they are the applied SOLs for that particular assessment.

## 3.4. System Assessment and General Performance Criteria

The system assessment and general performance criteria identified in this section should be the same for both planning and operations horizon unless otherwise noted below.

As required by NERC Reliability Standard TPL-001-4[[6]](#footnote-7), in the pre-contingency state and with all facilities in service (planning horizon[[7]](#footnote-8)), 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 expected system conditions and shall reflect changes to system topology such as Facility outages [FAC-010-3R2.1; FAC-011-3 R2.1].

As required by NERC Reliability Standard TPL-001-4, starting with all Facilities in service (planning horizon7), and following any of the contingencies identified for NERC Reliability Standard TPL-001-4, Category P1, 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. [FAC-010-2.2 R2.2.1, R2.2.2, R2.2.3; FAC-011-3 R2.2, R2.2.1, R2.2.2, R2.2.3]. Starting with all Facilities in service (planning horizon7), the system’s response to a single contingency may include any of the following [FAC-010-3 R2.3; FAC-011-3 R2.3]:

* 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 [FAC-010-3 R2.3.1; FAC-011-3 R2.3.1].
* System reconfiguration through manual or automatic control or protection actions [FAC-010-3 R2.3.2; FAC-011-3 R2.3.3].

For the operations horizon, the system’s response to a single contingency may also include any of the following [FAC-011-3 R2.3]:

* 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. [FAC-011-3 R2.3.1]
* Interruption of other network customers;

(a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or

(b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies [FAC-011-3 R2.3.2].

* System reconfiguration through manual or automatic control or protection actions. [FAC-011-3 R2.3.3]

To prepare for the next contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology [FAC-010-3 R2.4; FAC-011-3 R2.4].

As required by NERC Reliability Standard TPL-001-4, in the planning horizon, starting with all Facilities in service (planning horizon7), and following any of the multiple contingencies identified in NERC Reliability Standard TPL-001-4, 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 [FAC-010-3 R2.5]. The system’s response may include any of the following [FAC-010-3 R2.6]:

* 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 [FAC-010-3 R2.3.1].
* System reconfiguration through manual or automatic control or protection actions [FAC-010-3 R2.3.2]
* Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers [FAC-010-3 R2.6.1]. It should be noted that there are no firm transfers within the ERCOT Interconnection.

## 3.5. Study modeling and conditions

Planning Horizon:

Study cases published by the ERCOT Steady-State Working Group (SSWG), ERCOT Dynamics Working Group (DWG) or ERCOT Regional Transmission Plan are used for planning horizon assessments [FAC-010-3 R3.1]. These cases will contain the best estimate of any planned transmission line maintenance outages, system configuration, anticipated generation dispatch, and load levels. Additional system conditions, such as a minimum load case or high wind / low load case, may also be studied if needed. [FAC-010-3 R3.5]. The study of additional system conditions, such as a higher load level, may provide additional reliability margin to the study cases selected.

The study models used in planning horizon analyses represent the entire ERCOT Transmission system, including all Facilities 60 kV and above. The ERCOT Transmission system has a limited amount of flow capability between ERCOT and other Interconnections, all through DC-ties. Therefore, ERCOT ISO models these interconnections in the base case data sets as generation or load using historical flow information. The level of detail in the system models used in the analysis is consistent with the SSWG and DWG manuals and processes [FAC-010-3 R3.1, R3.3]. The 60 kV and above threshold provides reliability margin to the study model that is above required obligations.

The contingencies selected for planning horizon analyses reference NERC TPL-001-4 Standards as a minimum analysis criteria [FAC-010-3R3.2].

Where appropriate, simulations of actions by Remedial Action Schemes (RAS), as defined by NERC, or Automatic Mitigation Plans (AMP), as defined in ERCOT regional rules, are allowed, and may be included in the studies. Inclusion of specific RAS or AMP actions will be determined by the impact the RAS or AMP would potentially have on Facilities in the studies e.g. (If a RAS or AMP is not in the area and does not impact a Facility in the area, it would not be included). Also, if the impact of the RAS or AMP does not affect the type of limit being determined, it may not be included [FAC-010-3 R3.4].

Operations Horizon:

The ERCOT ISO uses several different types of models in the operations horizon based on the study type. The following applies to ERCOT ISO.

The Network Operations Model is the primary model used in the operations horizon. The SSWG case may be used to conduct steady-state studies in operations planning horizon (seasonal and beyond up to one year). The DWG case modeling information may be used to provide dynamic modeling data into the Transient Security Assessment Tool (TSAT). The Network Operations Model, SSWG, and DWG cases have the known current or expected system topology modeled for the ERCOT Interconnection Bulk Electric System (BES), and includes non-radial facilities 60 kV and above within the ERCOT Transmission system [FAC-011-3 R3.1, R3.4]. The 60 kV and above threshold provides additional reliability margin to the study model as it goes beyond the 100 kV BES definition.

The ERCOT ISO’s Network Operations Model consists of transmission lines, autotransformers, circuit breakers and switches, reactive devices, generation facilities and step-up transformers, loads, and other relevant electrical components. For each Network Operations Model prepared by ERCOT, ERCOT posts ratings and the ambient temperatures used to calculate any dynamic ratings on the MIS Secure Area when the model is published. The DWG study cases consist of similar information as mentioned above as well as additional details and modeling information necessary to perform dynamic and transient stability studies. The Network Operations Model, SSWG cases, and DWG cases are study models that are used to determine SOLs in the operations horizon [FAC-011-3 R3.1, R3.4].

The topology used in Energy Management System (EMS) applications, including the Study Network Analysis (STNET) application, is capable of using dynamic, temperature-adjusted ratings for specified transmission lines which Transmission Owners (TOs/TOPs) have previously identified through Network Operations Model Change Requests. Real-Time applications and tools will use the dynamic ratings, either through use of actual temperature information or telemetry received from the TOs/TOPs. The dynamic ratings of these lines are the SOLs unless otherwise limited by special transfer limits or stability limits. Future studies, based on the Network Operations Model, may use dynamic ratings based on expected weather conditions. [FAC-011-3 R3.4].

The contingency list used in the operations horizon includes, as a minimum, all non-radial BES transmission lines and BES transformers with a high side winding greater than 100 kV and at least one secondary winding greater than 100kV, and all BES generation facilities. Two transmission lines sharing the same tower for longer than 0.5 mile are modeled as a relevant system contingency. ERCOT ISO defines transmission line contingencies for all non-radial line segments that make up the circuit between two or more fault relaying breakers/disconnect switches located at two or more switching stations. Similarly, contingencies for autotransformers are defined for the autos and their corresponding fault relaying breakers and switches. [FAC-011-3 R3.2].

ERCOT ISO considers expected system conditions for the future operations time horizon to determine if a stability limit identified in the planning horizon is applicable in the operations horizon. Any multiple contingencies associated with the stability limits are reviewed as part of the study that identified the stability limits, through coordination between planning and operations, to determine if they are credible multiple contingencies in the operations horizon. ERCOT ISO considers other currently used credible multiple contingencies in the operations horizon as a basis for inclusion in the list of associated multiple contingencies related to the stability limit. The credible multiple contingencies (associated with the stability limits), that were determined to be applicable in the operations horizon, are modeled and or modified as necessary. Stability limits associated with more than one transmission element are modeled in the Network Model as an interface (a set of transmission lines whose flow is aggregated), and are typically managed through the use of a generic transmission constraint[[8]](#footnote-9). The numeric values of the limits are calculated prior to operational studies that utilize the limits and are updated as necessary. [FAC-011-3 R3.3, R3.3.1].

Contingencies identified during the review for operations horizon are monitored in Real-Time using Real-Time applications and tools. ERCOT ISO uses the Voltage Security Assessment Tool (VSAT) and Transient Security Assessment Tool (TSAT) in Real-Time to determine and monitor stability limits, including stability limits that are SOLs. Reliability margins are established for stability limit SOLs through off-line studies and or operational experience, and applied in Real-Time. These reliability margins are intended to allow time to respond to potential exceedances with the intent of avoiding an exceedance of identified stability limits.

When using an SSWG case, and where otherwise appropriate, simulations of RAS or AMP actions are allowed and included in the studies. This would be determined by the impact the RAS or AMP would have on Facilities in the studies e.g. (If a RAS or AMP is not in the area and does not impact a Facility in the area, it would not be included.) If the impact of the RAS or AMP does not affect the type of limit being determined, it may not be included. When using the Network Operations Model as the study case, RASs or AMPs are always evaluated as they are modeled as part of the Network Operations Model, unless the RAS or AMPs is in outage. RAS or AMPs are allowed in Voltage Security Analysis Tool (VSAT) and Transient Security Analysis Tool (TSAT) as needed. [FAC-011-3 R3.5].

Anticipated topology, generation dispatch and load levels are utilized in performing studies in the operations horizon. Anticipated topology is incorporated by including planned transmission and resource outages into the study cases, where appropriate. Generation dispatch is incorporated by using a typical generation dispatch pattern for a particular load level for studies up to Real-Time. Generation dispatch may also be incorporated by using Current Operating Plans (COPs) which are required to be provided by Generator Operators (GOPs) from Real-Time through seven days in the future. Current Operating Plans are updated as necessary. Load levels are incorporated by using historical loads and load forecasts as appropriate. Reliability margins may be applied by using a conservative load forecast, conservative historical load, or by biasing the load forecast in a conservative fashion as appropriate. Operating reserves also provide additional reliability margin to account for unplanned outages and forecast error [FAC-011-3 R3.6].

## 3.6. Determination Criteria

Based on the assessment results in Section 3.4, additional SOLs are identified if the system performance results in any of the following:

* + - Transient, dynamic instability (resulting in the loss of a generator due to the instability);
    - Voltage instability (resulting in voltage collapse);
    - Cascading[[9]](#footnote-10) or uncontrolled separation;
    - Voltage stability margin in the planning horizon is not sufficient to maintain post-transient voltage stability under the following two conditions for an ERCOT or TP-defined area:
      * A 5% increase in Load above expected peak supplied from resources external to the ERCOT or TP-defined area and NERC planning events P0 and P1 operating conditions; or
      * A 2.5% increase in Load above expected peak supplied from resources external to the ERCOT or TP-defined area and NERC planning events P2 through P7 operating conditions;
    - Post disturbance frequency outside the range from 59.4 Hz to 60.4 Hz[[10]](#footnote-11); or
    - Manual system adjustments in the planning horizon, such as system reconfiguration and re-dispatch of generation between contingencies in a planning event, or load shedding are needed in order to prevent Cascading or transient, dynamic, or voltage instability.

ERCOT ISO, the TPs, or the TOPs may deviate from these criteria as necessary but should justify the reasoning for such deviation and the deviation should maintain or improve system reliability.

An SOL is an IROL if the system performance response results in:

* + - Loss of load in the Cascading or voltage collapse, either through manual action or as a consequence of the event (including loss of load as a result of Under Voltage Load Shedding (UVLS), is greater than a threshold as defined in Section 3.7 of this methodology.
* Trigger of automatic under frequency load shedding[[11]](#footnote-12)
* Observable inter-area oscillation with damping ratio less than 3%.

The IROL Tv is 30 minutes unless a lower Tv is identified. [FAC-010-3 R1.3, R3.6; FAC-011-3 R1.3, R3.7]. The IROL Tv may be set lower using engineering judgment, by considering factors such as, but not limited to, the risk of the event, equipment limitations and history of equipment operation in the area.

## 3.7. Load Loss Threshold Guidelines

In the planning horizon and operations horizon, the value of the load loss threshold for a particular study will be six times 1% of the ERCOT Interconnection load level used in that study (6 x 1% x aggregate load level). ERCOT ISO, the TPs, or the TOPs may deviate from this guideline as necessary but should justify the reasoning for such deviation and the deviation should maintain or improve system reliability.

The basis is that since frequency response for the ERCOT Interconnection is typically around 1% of system load for each .1 Hz change in frequency, by multiplying by a value of 6 (to represent a 0.6 Hz frequency response) results in a MW value that should result close to a 0.6 Hz frequency deviation. In ERCOT, generator protection is set greater than 60.6 Hz, based on ERCOT regional rules. While load of this magnitude will not typically be lost simultaneously, the guideline assumes simultaneous loss of load with no automatic frequency response which can be considered reliability margin [FAC-010-3 R3, R3.6; FAC-011-3 R3, R3.7].

# 4. Distribution of Documents and SOLs

This methodology is posted on the ERCOT ISO Market Information System (MIS) Public website. Notifications related to revisions of the *SOL Methodology for the Planning Horizon and Operations Horizon* will be made prior to the effective date of the change. When the methodology is revised, a notification of update is sent to each TOP and TP in the ERCOT Interconnection (typically through a market notice, however other equivalent means may be used) [FAC-010-3 R4.2, R4.3; FAC-011-3 R4.2, R4.3]. Notification of revisions to the RC is internal to ERCOT ISO as the single PA and RC in the ERCOT Interconnection Any other PA and or RC that demonstrates it has a reliability-related need for the methodology will be provided the current copy of this *SOL Methodology for the Planning Horizon and Operations Horizon*. A notification of update is sent to that PA and/or RC for any future revisions, if such is requested [FAC-010-3 R4, R4.1, R4.2; FAC-011-3 R4, R4.1, R4.2]. If a recipient of this Methodology provides documented technical comments on the Methodology to SOLmethodology@ercot.com, ERCOT ISO will provide a documented response to that recipient within 45 calendar days of receipt. The response will indicate whether a change will be made to this Methodology or, if no change will be made, the reason why [FAC-010-3 R5; FAC-011-3 R5].

ERCOT ISO (acting as the PA) sends the assessment results annually to each NERC TOP and TP in the ERCOT Interconnection through either an e-mail distribution list or an ERCOT market notice. The results will be shared within ERCOT ISO, as appropriate. Internal communications will include the list of multiple contingencies and the associated stability limits, or notification that results did not identify any stability-related multiple contingencies [FAC-014-2 R5.3, R6.1, R6.2].

ERCOT ISO (acting as the RC) provides SOLs that ERCOT ISO has developed, including those SOLs that are identified as an IROL, to the TOPs and TPs in the ERCOT Interconnection that have a demonstrated need and provide a written request that includes a schedule for delivery of those limits. ERCOT provides information on new stability limits that could become an SOL, through the process of adding generic transmission constraints[[12]](#footnote-13). ERCOT provides thermal based congestion and voltage limits as noted in Section 3.5 of this document for each Network Operations Model. ERCOT ISO (acting as the RC) will also provide SOLs to any other RCs that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits [FAC-014-2 R5, R5.1]. SOLs will be shared within ERCOT ISO, as appropriate, to ensure SOLs are fed back to the planning horizon as necessary [FAC-014-2 R5.1]. Any IROLs that are provided contain the information provided below [FAC-014-2 R5.1].

* Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.
* The value of the IROL and its associated Tv.
* The associated Contingency (ies).
* The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

As systems change throughout the time horizons, some or all of this information may change. As such, the details which are not modified may not be provided each additional time, as the characteristics did not change. For conciseness, only the elements which are modified may be communicated. An example may be where the limit changes, but the contingencies, type of limit, and facilities that make up an interface do not change. In such an instance, only the new limit would be provided as an update [FAC-014-2 R5.1].

It is expected TPs will provide any SOLs they have developed, in addition to the Facility rating SOLs, to ERCOT ISO and the TP’s neighboring entities as appropriate, in accordance with this methodology [FAC-014-2 R4, and R5.4].

It is expected that TOPs will provide any Facility Ratings, any special transfer limits, and any stability limits to ERCOT ISO in accordance with this methodology [FAC-014-2 R2 and R5.2].

In the unlikely event that a new IROL is determined due to real time conditions, and it is determined to have a likelihood of occurring again due to future anticipated operational conditions,

a constraint management plan is coordinated with the affected TOP(s), as necessary and is either posted on the ERCOT MIS or provided to affected TOP(s)/TP(s) via other means. Additional information concerning the IROL will be provided to the TOPs and TPs in the ERCOT Interconnection that have a reliability related need and provide a written request that includes a schedule for delivery of those limits. [FAC-014-2 R5, R5.1]. SOLs will be shared within ERCOT ISO, as appropriate, to ensure SOLs are fed back to other operations horizon staff and the planning horizon as necessary [FAC-014-2 R5.1].

A list of Generation Facilities at a single plant location, or Transmission Facilities that are identified to be critical to the derivation of an IROL, and/or the station or substation locations that are associated with the initiating contingencies leading to the identification of an IROL, are sent to the appropriate NERC GOs, GOPs, TOs and TOPs to assist those entities in identifying generation and transmission Facilities that meet the criteria defined in CIP-002-5.1, Attachment 1 Criterion 2.6 and Criterion 2.9.

# 5. System Operating Limit Retirement

As system topology changes over time, SOLs may need to be retired. Some system changes that could warrant retirement of a SOL could include but are not limited to;

* New or rerated resources
* New or rerated transmission facilities
* Load modeling/characteristic changes
* Changes to operational practices/controls/systems

A Market Participant may request ERCOT ISO to consider retiring an SOL.

The following generic steps are offered as a guideline that can be followed as a process to retiring a SOL (including IROLs) in the operations horizon. These steps are applicable to SOLs that are determined based on interface or stability limits and not meant to address when the SOL is always based off the Facility Ratings or steady-state voltage limits. Planning horizon SOLs are evaluated annually through existing processes and will simply cease being an SOL when a limit no longer appears or is no longer the most limiting of prescribed planning criteria.

1. ERCOT ISO initializes an assessment based on operational observations or predicted operational conditions due to system changes, where an interface or stability limit is no longer the most restrictive limit consistent with this SOL methodology. The assessment should assess stressed conditions and anticipated system outages for the particular limit (e.g. peak, off peak, high-wind low load, high-wind high load, outage season) within the operations horizon. Study modeling and conditions should be consistent with Section 3.5.
2. ERCOT ISO validates that the system performance did not result in any of the SOL determination criteria identified in Section 3.6 and was consistent with performance criteria identified in Section 3.4, in consultation with affected TOPs and affected TPs.
3. ERCOT ISO communicates the retirement of the SOL to all affected parties including but not limited to:
   1. Affected Transmission Operators.
   2. Affected Transmission Planners
   3. NERC and/or Texas RE as appropriate
   4. Internal to ERCOT as appropriate
   5. Other appropriate parties

With an effective date that is at least 30 calendar days in advance.

1. Retire any associated Operating Plans or procedures associated with the retired SOL.

# 6. Document Revisions

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| --- | --- | --- | --- |
| **Version** | **Description** | **Revision Date** | **Author(s)** |
| 0 | Final Draft | 07-May-2013 | J. Chen; J. Billo; S. Solis |
| 0.1 | Minor edits to Final Draft | 23-Sept-2013 | J. Chen; J. Billo; S. Solis |
| 0.2 | Edits from comments submitted; extension of effective date to resolve Section 3.3. | 13-Sept-2013 | J. Chen; J. Billo; S. Solis |
| 0.3 | Edits from comments submitted; extension of effective date to allow for potential additional comments prior to effective date. | 24-Jan-2013 | J. Chen; J. Billo; S. Solis |
| 1 | Annual Review; minor clarifications; addition of section for SOL Retirement process and language for Real Time IROL determination criteria; referencing planning steady-state voltage limits to planning guides and aligning new definitions and standard revisions. | 5-Dec-2014 | B. Blevins; J. Billo; S. Solis |
| 1.1 | Clarifications and revisions based off of comments received and additional review. | 4-Feb-2015 | B. Blevins; J. Billo; S. Solis |
| 2 | Annual Review; minor clarifications; and aligning new definitions. | 15-Dec-2015 | N. Mago; J. Billo; S. Solis |
| 2.1 | Clarifications and revisions based on comments received and additional review. | 22-Feb-2016 | N. Mago; J. Billo; S. Solis |
| 3 | Annual Review; replacing SPS with RAS or AMP to align with NPRR 792 and NOGRR 164. | 04-Nov-2016 | F. Garcia; J. Billo; S. Solis; C. Thompson |

1. ERCOT Protocols define the Emergency Rating for the ERCOT Interconnection to be: “the two-hour MVA rating of a transmission element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The transmission element can operate at this rating for two hours without violation of NESC clearances or equipment failure.” [↑](#footnote-ref-2)
2. Facility Ratings in the ERCOT Interconnection include the Normal Rating, Emergency Rating, and the 15-Minute Rating. ERCOT Protocols define the 15-minute rating to be: “The 15-minute MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The Transmission Element can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with heating of a conductor or transformer following a sudden increase in current.” [↑](#footnote-ref-3)
3. These may include any special transfer or stability limits determined as part of Facility Interconnection Studies. [↑](#footnote-ref-4)
4. 1.10 per unit is higher than the default planning steady-state system voltage limit of 1.05 per unit to allow for operational flexibility in instances where Facility owners have not communicated a more restrictive limit. [↑](#footnote-ref-5)
5. These voltage limits should be communicated at a minimum through a Network Operations Model Change Request (NOMCR) so that it will be incorporated into the Network Model for use in studies in the operations time horizon. [↑](#footnote-ref-6)
6. TPL-001-4 mandatory effective date for all requirements is 1/1/2016. FAC-010-3 still references older TPL standards. This document references TPL-001-4 to be consistent with planning studies moving forward until FAC-010-3 is updated. [↑](#footnote-ref-7)
7. While ERCOT ISO’s planning horizon studies start with all Facilities in service, operation horizon studies typically begin with either current or expected system topology. [↑](#footnote-ref-8)
8. Generic Transmission Constraints (GTCs) are created to monitor one or more grouped Transmission Elements for managing stability, voltage, or other constraints that cannot be modeled directly in ERCOT ISO’s power flow and contingency analysis applications. [↑](#footnote-ref-9)
9. An engineer may choose to not identify an SOL for a cascading event if the consequences are deemed insignificant in the context of the reliability of the Interconnection. In making this determination the engineer will consider factors/thresholds such as, but not limited to, total load loss (for example, total load loss is less than 500 MW or a threshold specified by the engineer), an existing Facility Rating exceedance, or the total number of cascade iterations for the event. [↑](#footnote-ref-10)
10. Under frequency load shed is set at 59.3 Hz in ERCOT; therefore, 59.4 Hz is used to determine SOLs in order to preserve a 0.1Hz margin. Generator protection is set greater than 60.6 Hz, in ERCOT; therefore, 60.4 Hz is used to determine SOLs in order to preserve a 0.2 Hz margin. This applies for the identification of SOLs in dynamic assessments in the Planning Horizon. [↑](#footnote-ref-11)
11. This does not include Load Resources with high set under frequency set points. [↑](#footnote-ref-12)
12. Generic Transmission Constraints (GTCs) are created to monitor one or more grouped Transmission Elements for managing stability, voltage, or other constraints that cannot be modeled directly in ERCOT ISO’s power flow and contingency analysis applications. [↑](#footnote-ref-13)