Appendices to
Reliability Coordinator Area
System Operating Limit Methodology
Western Interconnect

Revision 1.0

MAINTAINED BY
SPP Operations Staff

PUBLISHED: 08/30/2019

Copyright © 2019 by Southwest Power Pool, Inc. All rights reserved.
REVISIONS

<table>
<thead>
<tr>
<th>Revision</th>
<th>Date</th>
<th>Description of Modification</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0</td>
<td>8/30/2019</td>
<td>Initial Version Issued</td>
</tr>
</tbody>
</table>

TABLE OF CONTENTS

A. Damping Ratio Calculation Example ................................................................. 3
B. SPP RC Recommendations for Determining Always Credible MCs ................................. 4
C. SPP RC Recommended Best Practices and Rationales .............................................. 4
   C.1 Operating Plans ......................................................................................... 4
   C.2 Controlled Separation Versus Uncontrolled Separation ...................................... 5
   C.3 Rationale for Lowest Allowable System Voltage Limit ....................................... 6
   C.4 Transient Stability Performance ....................................................................... 7
   C.5 Voltage Stability Performance Example .......................................................... 7
   C.6 System Stressing Methodology ........................................................................ 7
      C.6.1 Differing Objectives for System Stressing .................................................. 8
      C.6.2 Stressing Requirements to Determine Instability Risks .................................. 9
D. Interconnection Reliability Operating Limit (IROL) ............................................ 12
   D.1 Conditional IROL Study Methodology .............................................................. 12
      D.1.1 Rationale for Conditional IROLs ................................................................. 14
      D.1.2 Process for Identifying Conditional IROLs .................................................... 14
      D.1.3 Conditional IROL Example ......................................................................... 16
   D.2 Planned Outage Conditions IROL Study Methodology ......................................... 16
      D.2.1 Identifying POC IROLs .............................................................................. 17
   D.3 Facility Rating-Based IROL Study Methodology ............................................... 18
      D.3.1 Facility Rating-Based IROLs - Credible MC (Example 1) ............................... 18
      D.3.2 Conditional Facility Rating Based IROL (Example 2) ..................................... 19
   D.4 IROLs and Risk Management for Local and Contained Instability ........................... 19
      D.4.1 Possible Process for Determining Acceptable Levels of Risk - IROL ............... 20
A. Damping Ratio Calculation Example

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 during a ten-second run is about two seconds after the fault clears as most automatic schemes have switched and the fault should be fully cleared.

Note that the approximate formula \[ \delta/(2\cdot\pi) = 0.049 \times 100 = 4.9\% \text{ damping ratio} \]

Where \( n \) = Number of periods between measurement \( X_0 \) and measurement \( X_n \) Periods = 5 in example

\( X_0 \) is magnitude of oscillation at first measurement

\( X_n \) is magnitude of oscillation at second measurement Ln = log in base

\[ \delta = 0.305 \]
B. SPP RC Recommendations for Determining Always Credible MCs

TOPs could consider the following MC types when determining any Always Credible MCs for operations. These Contingency types serve as a starting point for the internal risk assessment for determining the Always Credible MC list:

A. Bus Fault Contingencies
B. Stuck breaker Contingencies
C. Relay failure Contingencies where there is no redundant relaying
D. Common structure Contingencies
E. Any of the MCs that have been determined by its PC to result in Stability Limits (provided to the RC per FAC-014-2 R6) [NERC Standard FAC-011-3 R3.3.1]

TOPS are encouraged to make Internal Risk Assessments available to other TOPs upon request.

C. SPP RC Recommended Best Practices and Rationales

C.1 Operating Plans

Operating Plans may include:

- Both pre- and post-Contingency mitigation plans/strategies.
  - Pre- Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability associated with the Contingency.
  - Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits.
- Details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-3, Requirement R2.
- The appropriate time element to address potential SOL exceedances.
### Recommended Operating Plan Checklist

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Is purpose of the Operating Plan clearly stated?</td>
</tr>
<tr>
<td>2</td>
<td>Are any limits and monitored interfaces, if applicable, clearly defined?</td>
</tr>
<tr>
<td>3</td>
<td>Are limiting facilities and Contingencies clearly identified?</td>
</tr>
<tr>
<td>4</td>
<td>Are applicable RAS and their actions identified?</td>
</tr>
<tr>
<td>5</td>
<td>Are the impacted entities clearly identified?</td>
</tr>
<tr>
<td>6</td>
<td>Are the mitigation measures and timeframes for implementation clearly stated?</td>
</tr>
<tr>
<td>7</td>
<td>Were the technical studies that identified the need for the Operating Plan coordinated with impacted TOPs?</td>
</tr>
<tr>
<td>8</td>
<td>Have the mitigation measures been fully studied to resolve the issue?</td>
</tr>
<tr>
<td>9</td>
<td>Is the procedure necessary to prevent instability, Cascading or uncontrolled separation?</td>
</tr>
<tr>
<td>10</td>
<td>Has the Operating Plan been coordinated with impacted entities?</td>
</tr>
</tbody>
</table>

### C.2 Controlled Separation Versus Uncontrolled Separation

1) Controlled separation is achieved when there is an automatic scheme that exists and is specifically designed for the purposes of:

   a) Intentionally separating the system.

      i) Note that such schemes may be accompanied by generation drop schemes or UFLS that are designed to shed load or drop generation to achieve generation/load equilibrium upon occurrence of the controlled separation.

   b) Intentionally mitigating known separation conditions.

      i) I.e., a scheme that is designed specifically to drop load or generation to achieve generation/load equilibrium upon a known Contingency event that poses a separation risk.
2) Post-Contingency islanding due to transmission configuration does not constitute uncontrolled separation.
   a) There are occasions where planned or forced transmission outages can render the transmission system as being configured in a manner where the next Contingency (single Contingency or credible MC) can result in the creation of an island. Operators are made aware of these scenarios through outage studies, OPAs and/or RTAs, and are expected to have Operating Plans that would address the condition in a reliable manner. Such conditions should consider the associated risks and mitigation mechanisms available; however, they are excluded from the scope of uncontrolled separation for the purposes of IROL establishment.

3) Examples of controlled separation:
   a) Example 1: A RAS is designed specifically to break the system into islands in an intentional and controlled manner in response to a specific Contingency event(s). Supporting generation drop and/or UFLS are in place to achieve load/generation equilibrium.
   b) Example 2: A UFLS is specifically designed to address a known condition where a credible MC is expected to create an island condition.

C.3 Rationale for Lowest Allowable System Voltage Limit

The 0.8 pu is based on the calculated Stability point for a single unit to infinite bus uncompensated system (0.707 pu) plus 10% margin (0.777 pu) which is then rounded up to 0.8 pu. The actual system is likely less favorable than the single unit to an infinite bus so a 10% margin is applied.
C.4 Transient Stability Performance

The system is typically considered to demonstrate acceptable positive damping if the damping ratio of the power system oscillations is 3% or greater.

C.5 Voltage Stability Performance Example

One representation of a voltage Stability Limit is the maximum pre-Contingency megawatt power transfer for which a post-Contingency solution can be achieved for the limiting (critical) Contingency (i.e., the last good solution established the voltage Stability Limit). P-V and V-Q analysis techniques are used as necessary for the determination of voltage Stability Limits. While megawatt power transfer represents one approach for defining a voltage Stability Limit, other units of measure (such as VAR limits) may be used, provided this approach is coordinated between the TOP and the RC.

Recommended Transient Performance for BES buses serving load¹:

a. Following fault clearing, the voltage typically recovers to 80% of the pre-contingency voltage within 20 seconds.²

b. Following fault clearing and voltage recovery above 80%, voltage typically neither dips below 70% of pre-contingency voltage for more than 30 cycles nor remains below 80% of pre-contingency voltage for more than two seconds.

c. For Contingencies without a fault voltage dips at each applicable BES bus serving load typically neither dips below 70% of pre-contingency voltage for more than 30 cycles nor remains below 80% of pre-contingency voltage for more than two seconds.

C.6 System Stressing Methodology

The objective of this system stressing methodology is to either identify possible instability risks or to rule them out for expected operating conditions for Operating Horizon studies.

1. If instability risks are identified, there is a need to establish Stability limits (which may include implementing Real-time Stability Limit calculators) and/or to establish Operating Plans to address those instability risks.

¹ A BES bus that is serving load is the bus with direct transformation from BES-level voltage to distribution-level voltage that serves load.
² TPL-001-WECC-CRT-3.1 WR1.3, WR1.4 and WR 1.5
2. If instability risks are ruled out for expected operating conditions, then subsequent reliability analyses might exclude Stability analyses for the Operating Horizon, provided system conditions are comparable to those represented in prior studies.

If instability risks can be ruled out for expected operating conditions, then subsequent reliability analyses – i.e., Operational Planning Analyses (OPA) and Real-time Assessments (RTA) – using steady-state Contingency analysis of actual or expected conditions, are sufficient to confirm that the system can be reliably operated within acceptable pre- and post- Contingency performance requirements with regard to Facility Ratings and System Voltage Limits.

C.6.1 Differing Objectives for System Stressing

Transfer analyses that stress the power system are performed to determine the pre- and post-Contingency reliability issues that can be encountered as transfers increase into a load area or across a transmission interface. How far the system is stressed as part of transfer analyses depends on the purposes and objectives of the analysis.

If the purpose of the transfer analyses is to determine Transfer Capability (TC) or TTC, the system generally needs to be stressed only to the point where a reliability limitation is encountered (with an applicable margin). In principle, TCs are generally determined by stressing the system until either of the following reliability constraints is encountered:

- In the pre-Contingency state, flows exceed normal Facility Ratings, voltages fall outside normal System Voltage Limits or instability occurs (i.e., the system is stressed to the point of unacceptable pre-Contingency performance with regard to thermal, steady-state voltage or instability constraints).
- In the post-Contingency state, flows exceed emergency Facility Ratings, voltages fall outside emergency System Voltage Limits or instability occurs (i.e., the system is stressed to the point of unacceptable post-Contingency performance with regard to thermal, steady-state voltage or instability constraints).

Most paths in WECC are either thermally limited or steady-state voltage limited, as opposed to transient stability or voltage stability limited. For these paths, transfer analyses have shown that the first reliability limitations encountered are post-Contingency exceedances of emergency Facility Ratings or emergency System Voltage Limits. For example, when stressing a path, transfer analyses indicate that at a certain level of transfer, a single Contingency or a credible MC result in exceedance of another Facility’s emergency Facility Rating. Similarly, these transfer analyses may
indicate that at a certain level of transfer, single Contingency or a credible MC result in voltage at a bus falling outside its emergency System Voltage Limit.

While TC studies do not require that the system be stressed appreciably beyond the point of encountering the first reliability limitation, the same cannot be said for transfer analyses that are performed for purposes of determining whether instability risks exist for expected system conditions. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a first reliability limitation, it may be necessary to identify where subsequent operation may approach a point of instability.

To adequately determine whether instability risks exist for expected system conditions for a given transmission interface or load area, the system must be stressed beyond the point where thermal or voltage limitations are encountered. The question is: how far does the system need to be stressed before instability risks can be ruled out for all practical purposes?

Note that transfer analyses for purposes of determining TC or TTC are outside the scope of the SOL Methodology.

### C.6.2 Stressing Requirements to Determine Instability Risks

Transient instability, voltage instability or Cascading may occur in response to a single Contingency or a credible MC under stressed conditions. Under this methodology, it is the primary responsibility of the TOP to identify or rule out instability risks and to determine how far transmission interfaces and load areas should be stressed to accomplish this intended objective. System stressing requirements depend on several factors and therefore cannot be specified in a one-size-fits-all approach. While the system should be stressed far enough to accomplish the intended objective, the expectation of this methodology is to stress the system up to – and slightly beyond – reasonable maximum stressed conditions. It is not the intent of this methodology for TOPs to stress the system unrealistically or to stress the system to levels appreciably beyond those that are practically or realistically achievable.

This methodology should be applied to applicable studies performed in the Operations Horizon including, at a minimum, seasonal studies and outage coordination studies as determined to be necessary by the TOP. While the stressing methodology may optionally be applied to Operational Planning Analyses and Real-time Assessments, it is not required. For transmission interfaces that span multiple TOP Areas, the TOPs that operate the Facilities on the interface are encouraged to coordinate to determine appropriate levels of stressing necessary to identify or rule out instability risks. TOPs are encouraged to document stressing levels performed in operations planning studies.
and to communicate these levels and the results of these analyses to the RC when instability or Cascading is identified.

The following considerations should be used as a guideline to determine appropriate levels of system stressing:

1. Source area is exhausted – When stressing a transmission interface, in some cases it is possible to maximize the source area in the simulation before any reliability issues (Facility Ratings, System Voltage Limits or instability) are encountered. If the source area is exhausted in simulations, then it can be concluded that there is no way to realistically simulate any additional transfers. Load should not be scaled unrealistically as part of increasing exports. For example, when simulating exports, it may be unreasonable to scale load down by 50 percent of its expected value to simulate exports. The TOP is encouraged to determine reasonable uses of load as a mechanism for simulating exports.

2. If the source is maximized before either the nose of a PV or VQ curve is reached, before transient instability occurs, or before Cascading takes place (per the Cascading test outlined in the SOL Methodology), then it can be concluded that no instability or Cascading risks practically exist for the interface and there is no reliability need to establish Stability limits for the interface or load area. Different methodologies will be used (as further discussed below) for transmission interfaces where source generation cannot be maximized in the simulation.

3. Sink area is depleted – When stressing an interface into a load area, it is possible to de-commit or reduce the output of all generators internal to the load area (i.e., serve the load with ~100 percent imports) before any pre- or post-Contingency reliability issues (Facility Ratings, System Voltage Limits or instability) are encountered. Entities should model the expected minimum generation commitment in the load sink area at the expected maximum import level and simulate largest generation Contingency as part of simulations. If the generation internal to the sink load area is decreased to the minimum generation commitment level and the sink’s load is modeled at reasonably expected maximum conditions, then it can be concluded that there is no practical way to simulate any additional imports into the area. Load should not be scaled unrealistically as part of increasing imports. For example, when simulating imports, it may be unreasonable to scale load in the sink area up by 150 percent of its expected value to simulate imports. The TOP is encouraged to determine reasonable uses of load as a mechanism for simulating imports.
4. If the generation internal to the sink load area is depleted and load is maximized either before the nose of a PV or VQ curve is reached, before transient instability occurs, or before Cascading takes place (per the Cascading test outlined in the SOL Methodology), then it can be concluded that no Stability Limits or Cascading risks practically exist for the load area and there is no reliability need to establish a Stability Limit for the load area.

5. It may be possible to simulate flow on an interface or into a load area to levels that are unrealistic for operations. While it is encouraged that the system be stressed beyond the historical 2.5-to-5 percent levels for identifying or ruling out instability risks, the TOP, in collaboration with neighboring TOPs as necessary, are encouraged to determine reasonable maximum stressing conditions to identify or rule out instability risks. If the system is stressed to levels just beyond those determined by impacted TOPs as being reasonably expected maximums and no instability occurs in the simulations, or simulated flows do not reach the level where potential Cascading can occur, then it can be concluded that no instability or Cascading risks practically exist for the interface or load area and thus there is no reliability need for establishing stability limits or stability-related Operating Plans.

6. It is possible to stress the system to a point where potential Cascading is encountered. Cascading tests should be performed consistent with the Instability, Cascading, Uncontrolled Separation and IROLs section of the SOL Methodology. This analysis assumes that pre- and post-Contingency flows are below applicable Facility Ratings prior to the transfer analysis.

7. System stressing studies may result in transient instability or the nose of a PV or VQ curve being reached\(^3\) either under pre-Contingency conditions or upon occurrence of a single Contingency or credible MC. This condition indicates the presence of an instability risk and thus the need to establish a transient or voltage Stability Limit or to otherwise manage the instability risk via an Operating Plan.

8. Any instability or Cascading risks identified as a result of applying this system stressing methodology should be communicated to the RC. For identified Cascading or instability risks, the RC will collaborate with the TOP(s) in the establishment of Stability limits and Operating Plans to mitigate these risks.

\(^3\) If the nose is not reached and different solving techniques do not result in a solution, then the last solved solution determines the Stability Limit.
D. **Interconnection Reliability Operating Limit (IROL)**

When the SOL Methodology uses the term IROL, it is used in the context of the IROL being identified in studies performed one or more days prior to Real-time. Per the SOL Methodology, IROLs are always pre-identified through studies.

The RC is responsible for declaring IROLs. TOPs are not responsible for declaring IROLs; however, TOPs are responsible for communicating and collaborating with the RC when studies (seasonal studies, special studies, outage studies or OPAs) identify instability (whether contained or uncontained), Cascading or uncontrolled separation as described in the SOL Methodology. Upon this communication, the RC then collaborates with the TOP to determine if an IROL needs to be established to address these risks.

IROLs are established to prevent instability, uncontrolled separation or Cascading as described in the SOL Methodology for:

1. Single Contingencies
2. Credible MCs

For identification purposes, the following three study methodologies may also be used to identify IROLs: Conditional IROLs; Planned Outage Condition (POC) IROLs; and Facility Rating-Based IROLs.

D.1 **Conditional IROL Study Methodology**

Conditional IROLs are identified to prevent instability, uncontrolled separation or Cascading as described in the SOL Methodology for:

1. N-1-1 and N-1-2 operations starting with an “all transmission Facilities in service” case, with system adjustments

Conditional IROLs are not effective under normal operating conditions (i.e., all critical transmission Facilities in service). Conditional IROLs will become effective and mitigation is required if any Conditional IROL is exceeded after the first critical Facility is out of service (planned or forced).

Conditional IROLs are identified through seasonal studies and through special studies conducted by the RC, by the TOP(s) or by the RC in collaboration with the TOP(s). However, it is the RC that ultimately declares IROLs for use in the Operations Horizon. Relevant information for Conditional IROL identification can be gleaned from several sources including, for example, prior...
operational experiences/events, planning studies performed in association with the NERC TPL standards, from planning studies performed in association with FAC-010-3, or corresponding requirements applicable to PCs and TPs in FAC-014-2.

**Note:** Conditional IROLs are not required to be established, but if the RC and TOPs agree to perform the analysis, then the following “Conditional IROLs” sections provide guidance on what to consider for N-1-1 and N-1-2 conditions:

**Application:**
1. Addresses known N-1-1 and N-1-2 risks that could result in instability, Cascading or uncontrolled separation as described in the SOL Methodology
2. Applicable to an “all transmission Facilities in service” starting point case(s)
3. Addresses N-1-1 and N-1-2 operations (with system adjustments) where:
   a. “N” is an “all transmission Facilities in service” case(s)
   b. The first “-1” is a forced outage or a single Contingency event
   c. The second “-1” is the next worst single Contingency, or the “-2” is the next worst MC
4. Conditional IROLs are not established for N-2-1, or N-2-2 conditions, due to the low probability of occurrence of the first “-2” Contingency event.

**Purpose:**

Conditional IROLs are intended to pre-identify and prepare for the following scenario:
1. The system is being operated in a normal operating condition The system demonstrates acceptable system performance for the pre- and post-Contingency state.
2. A single Contingency or a forced/urgent outage of a single Facility occurs.
3. The system is now in a new and different state, system adjustments can be made.
4. Based on this new state, the next single Contingency or MC could result in instability, Cascading or uncontrolled separation as described in the SOL Methodology, and thus the system is now in an N-1 (or credible N-2) insecure state.
D.1.1 Rationale for Conditional IROLs:

Conditional IROLs can be identified and established to provide System Operators an awareness of instances where a single Contingency or a forced/urgent outage on a single Facility is predetermined by studies to render the system in a state where the next single Contingency or Always Credible MC can result in instability, uncontrolled separation or Cascading as described in the SOL Methodology.

1. Given an initial condition state of “all transmission Facilities in service” in a normal operating condition, if a single Contingency or a forced/urgent single Facility outage causes engineers/operators to re-position the system with the specific objective of preventing instability, Cascading or uncontrolled separation as described in the SOL Methodology for the next worst single Contingency or Always Credible MC, then the system is in an N-1 or N-2 insecure state until those system adjustments can be made to transition the system to an N-1 or N-2 secure state.

2. When N-1-1 or N-1-2 studies indicate that the first “-1” renders the system in an N-1 or N-2 insecure state where the next single Contingency or Always Credible MC can result in instability, Cascading or uncontrolled separation as described in the SOL Methodology, a Conditional IROL can be identified. This IROL would become effective when the first “-1” event occurs and would prevent the next single Contingency or Always Credible MC from resulting in instability, Cascading or uncontrolled separation as described in the SOL Methodology. Such IROLs will be in effect only upon a forced/urgent outage or Contingency of the first “-1” Facility.

3. For such predetermined N-1-1 and N-1-2 Conditional IROLs, it is acceptable to operate the system such that the first “-1” Contingency will result in exceeding the IROL, provided that System Operators know that they are able to mitigate the IROL within the IROL TV after the “-1” Contingency event occurs. If System Operators are not able to mitigate the IROL exceedance within the IROL TV after the first “-1” Contingency event occurs, then pre-Contingency actions must be taken such that System Operators are able to mitigate the IROL exceedance within the IROL TV after the first “-1” Contingency occurs.

D.1.2 Process for Identifying Conditional IROLs:

Conditional IROLs are identified using transient analysis and/or post-transient analysis techniques. The following analysis process should be used to determine if an N-1-1 or an N-1-2 IROL should be identified:
1. N-1-1 and N-1-2 analysis assumes an “all transmission Facilities in service” initial condition. Assessments are based on reasonable max stressing conditions and historical flows. Reference the system stressing methodology.

2. The first single Contingency is simulated.

3. System adjustments include allowable automatic actions such as governor response, automatic capacitor switching, RAS, etc. System adjustments shall not include operator initiated actions.

4. The next worst single Contingency or Always Credible MC is then simulated to determine if the Contingency results in instability, Cascading or uncontrolled separation as described in the SOL Methodology. The analysis of this next worst single Contingency or Always Credible MC event should account for allowable automatic schemes that are designed to address these Contingencies.

5. If the next single Contingency or Always Credible MC results in instability, Cascading or uncontrolled separation as described in the SOL Methodology, then the condition indicates that system adjustments must be made after the first “-1” Contingency, but before the second Contingency, to prevent the instability, Cascading or uncontrolled separation as described in the SOL Methodology from occurring. This fact points to the presence of an IROL that would become effective upon a forced/urgent outage or Contingency of the first “-1” Facility.

6. Once these risks are identified, the N-1-1 and N-1-2 studies should then identify system adjustments that must be made (and the timing associated with these adjustments) after the first “-1” Contingency event to prevent the second Contingency event from resulting in instability, Cascading or uncontrolled separation as described in the SOL Methodology. These system adjustments should be taken into consideration when developing the IROL Operating Plan. IROLs must be determined that can be applied upon a forced/urgent outage or a Contingency of the first “-1” Facility. These IROLs can be pre-established values, or they can be calculated in Real-time.

7. The lower of the relay setting or 125 percent Cascading test as described in the SOL Methodology applies for the determination of Cascading.

8. For identified IROLs for N-1-1 and N-1-2 conditions, Real-time N-1-1 and N-1-2 analyses/calculations are prudent to provide System Operators awareness as to whether
that IROL would be expected to be exceeded upon a Contingency or a forced/urgent outage of the first “N-1” Facility.

D.1.3 Conditional IROL Example:

Studies show that the loss of Facility X is expected to render the system in a position where a subsequent Contingency on Facility Y would result in wide-area voltage instability, i.e., that the loss of line X would render the system in an N-1 insecure state for Contingency Y. A Conditional IROL is identified to prevent the loss of Facility X, followed by a Contingency of Facility Y, resulting in wide-area voltage instability.

1. The Conditional IROL is identified on the monitored interface appropriate for determining wide-area voltage instability for the loss of Facility Y.

2. For this example, the Conditional IROL is monitored as the maximum MW flow (the last good solution) on the monitored interface above which the subsequent loss of Facility Y results in wide-area voltage instability.

3. The Conditional IROL becomes effective when Facility X experiences a forced/urgent outage. The Conditional IROL is not in effect unless there is a forced/urgent outage or Contingency of Facility X.

4. The IROL is exceeded when Facility X experiences a forced/urgent outage and subsequent Real-time Assessments indicate that the flow on the monitored interface is above the value where the loss of Facility Y results in wide-area voltage instability. The IROL can be a pre-established value, or it can be calculated in Real-time.

D.2 Planned Outage Conditions IROL Study Methodology

IROLs can be identified during planned outage conditions (POC). POC IROLs are temporary in nature and do not apply when the planned outage is not in effect. Additionally, POC IROLs are identified for the outage conditions as expected system conditions warrant. For example, a planned outage for Facility XYZ during the month of August when loads are high may require a POC IROL to be identified for the duration of that outage; however, an outage on that same Facility in November when loads are low may not require a POC IROL to be identified.

POC IROLs are generally not identified to address N-1-1 or N-1-2 operations during planned outages; however, TOPs and the RC may determine that it is prudent to identify an N-1-1 or an N-1-2 POC IROL for long-duration outages (such as those that are in effect for an entire season).
where the TOP and the RC collaboratively determine that there is a high risk for N-1-1 or N-1-2 instability risks while the outage is in effect.

**D.2.1 Identifying POC IROLs**

When transmission or generation outages are planned, the system must be studied to determine if the planned outage creates any new instability risks that otherwise would not practically exist. When the system is operated in a normal operating condition, many types of limitations exist – Facility Ratings, System Voltage Limits or Stability. In normal operating condition, the system is able to support transfers throughout the various seasons that are fairly well understood. When planned outages are brought into the equation, the system may not be able to support the transfer levels that it otherwise would be able to support.

Per the IRO-017 Outage Coordination process, BAs, TOPs and the RC are expected to perform studies/assessments to ensure that the BES will be in a reliable pre- and post- Contingency state while an outage is in effect. Acceptable system performance as described in the SOL Methodology is required while planned outages are implemented.

It is not the intent of the IRO-017 Outage Coordination Process or the SOL Methodology to be highly prescriptive for study/assessment requirements related to planned outages. TOPs are responsible for determining the level of study needed to achieve acceptable pre- and post-Contingency system performance while the outage is implemented. The level of complexity of TOP studies/assessments will vary depending the type and number of simultaneous outages and on the unique challenges and reliability issues posed by the outages. It is left to the judgment of the TOP to determine what level of analysis is appropriate for a given planned outage situation. TOPs are responsible for determining how far to stress their system to identify or rule out instability risks for the planned outage conditions. When determining how far to stress the system during planned outage conditions, TOPs should follow the guidance provided in the System Stressing Methodology.

While many planned outages require the development and implementation of outage specific Operating Plans to facilitate a given planned outage, some outages may also require the development of an IROL to facilitate the outage.

When planned outage studies indicate that, at reasonable and realistic maximum stressed conditions during the planned outage(s), a single Contingency or a credible MC results in instability, Cascading or uncontrolled separation as described in the SOL Methodology, an IROL is warranted to be identified for that planned outage.
D.3 Facility Rating-Based IROL Study Methodology

Facility Rating-based IROLs are identified when studies show that a Contingency results in excessive loading on a Facility, which triggers 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), consistent with the NERC definition of Cascading. The Cascading test is used to determine Cascading based on available Facility Ratings. Facility Rating-based IROLs prevent non-stability related Cascading due to excessive post-Contingency loading of Facilities [NERC Standard FAC-011-3 R3.7]. While such IROLs may be established as Conditional IROLs for N-1-1 or N-1-2 operations, they may also be established for credible MCs, or planned outage conditions to address the next worst single Contingency or the next worst credible MC.

For Facility Rating-based IROLs, the IROL will be identified on the initial excessively loaded Facility that is expected to be disconnected by automatic or manual action, leading to Cascading. The IROL value will be the lesser of the relay trip setting or 125 percent of the Emergency Rating. These IROLs will be monitored for their performance in the post-Contingency state through RTAs.

D.3.1 Facility Rating-Based IROLs - Credible MC (Example 1):

Studies show that credible MC X results in Facility Z loading up to or beyond the lower of the relay trip setting or 125 percent of its Emergency Rating. Cascading tests indicate that the MC X would result in Cascading. An IROL is established to prevent MC X from resulting in Cascading.

1. The Facility Rating-Based IROL is identified when it becomes a risk to reliability. For planned outage conditions, the IROL may be in effect during the planned outage. Otherwise, the IROL may need to be in effect at all times.

2. The Facility Rating-Based IROL is identified on the initial excessively loaded Facility that is expected to be disconnected by automatic or manual action, leading to Cascading. Accordingly, the IROL is the MVA or Amp value on Facility Z that results exceeding the lower of the Facility Z’s trip setting or 125 percent of its highest Emergency Rating.

3. The Facility Rating-Based IROL is monitored as the calculated post-Contingency flow on Facility Z in response to MC X.

4. The Facility Rating-Based IROL is exceeded when Real-time Assessments indicate that MC X results in flow on Facility Z exceeding the lower of its trip setting or 125 percent of its highest Emergency Rating.
D.3.2 Conditional Facility Rating Based IROL (Example 2):

“All transmission Facilities in service” studies show that the loss of Facility X is expected to render the system in a position where a subsequent Contingency on Facility Y would result in Facility Z loading up to or beyond the lower of the Facility trip setting or 125 percent of its highest Emergency Rating. Cascading tests indicate that the loss of Facility X followed by a subsequent Contingency on Facility Y (with no system adjustments between Contingencies) would result in Cascading, i.e. that the loss of line X would render the system in an insecure state for single Contingency Y. An IROL is identified to prevent the loss of Facility X, followed by a Contingency of Facility Y, from resulting in Cascading.

1. The Conditional Facility Rating-Based IROL is identified on the initial excessively loaded Facility that is expected to be disconnected by automatic or manual action, leading to Cascading. Accordingly, the IROL is the MVA or Amp value on Facility Z that results in its tripping, in this case it is 125 percent of its highest Emergency Rating.

2. The Conditional Facility Rating-Based IROL is monitored as the calculated post-Contingency flow on Facility Z for the loss of Facility Y.

3. The Conditional Facility Rating-Based IROL is not in effect unless there is a forced/urgent outage or Contingency of Facility X. The IROL becomes effective when Facility X experiences a forced/urgent outage.

4. The IROL is exceeded when there is a forced/urgent outage on Facility X, and subsequent Real-time Assessments indicate that a Contingency of Facility Y results in flow on Facility Z exceeding the lower of its relay trip setting or 125 percent of its highest Emergency Rating.

D.4 IROLs and Risk Management for Local and Contained Instability

When IROLs are established, the current set of NERC Reliability Standards require that System Operators take action up to and including shedding load to prevent exceeding that IROL. There may be planned or forced outage scenarios where the system is vulnerable to localized, contained instability. In prior outage scenarios where there are local, contained instability impacts, the severity and extent of the instability impact may represent an acceptable level of risk that may not warrant extreme operator action such as pre-Contingency load shedding to prevent the instability from occurring in response to a Contingency event.
When such scenarios are determined to represent an acceptable level of risk, the local, contained instability risk may be managed via an Operating Plan that does not include the use of an IROL and does not include pre-Contingency load shedding.

### D.4.1 Possible Process for Determining Acceptable Levels of Risk - IROL

When prior outage studies indicate that a localized, contained area of the power system is at risk of instability in response to the next worst single Contingency or credible MC:

1. TOPs determine the mitigations and a corresponding Stability Limit that would be required to prevent that Contingency from resulting in localized, contained instability. The Stability Limit would be expressed as a maximum flow value on a monitored interface, cutplane or import bubble for the conditions under study.

2. When studies indicate that all other mitigations have been exhausted and pre-Contingency load shedding is the only option remaining to prevent the Contingency from resulting in localized, contained instability, TOPs should determine the amount and location of load that must be shed pre-Contingency (at peak load for the period under study) to prevent the Contingency from resulting in localized, contained instability.

3. TOPs determine the amount of load (at peak for the period under study) that is at risk of being lost due to instability in response to the Contingency. This assessment should include a determination of the physical and electrical extent of expected instability (e.g., the specific station buses that are expected to experience voltage instability, the expected voltage levels at adjacent stations that represent the boundary of impact). The assessment should also include any relay action that is expected to occur that might isolate that area of impact.

4. If the amount of pre-Contingency load shedding required to prevent the Contingency from resulting in localized, contained instability (as determined in item 2) is relatively high compared to the amount of load that is at risk due to instability (as determined in item 3), then the TOP collaborates with the RC to determine the levels of acceptable risk and to create an Operating Plan that addresses the instability risk commensurate with those decisions. Accordingly, the Operating Plan might not include steps for pre-Contingency load shedding, depending on the risk management issues at hand. A key objective is to ensure that the mitigations prescribed in the Operating Plan are consistent with good utility practice.
5. If it is determined that the localized, contained instability represents an unacceptable level of risk, and pre-Contingency load shedding is warranted to prevent the Contingency from resulting in the local, contained instability, then an IROL should be established by the RC to prevent the Contingency from resulting in the localized, contained instability. In such scenarios, the IROL will be based on the Stability Limit determined in item 1, and the IROL Operating Plan will be based on the information determined in item 2.