Transient Voltage Criteria Reference Document

This document submitted to NERC for consideration as "Implementation Guidance." NERC chose not to endorse the document. Visit NERC's compliance guidance website for more information.

NATF subject-matter experts are reviewing NERC's rationale for non-endorsement and will determine appropriate next steps and guidance for use of this document.

Contents

1 Introduction

1.1 Purpose of the Paper

The purpose of this reference document is to:

1. Provide historical background on transient voltage response criteria
2. Document NATF member utility practices regarding transient voltage response criteria
3. Help utilities respond to NERC TPL-001-4 requirement for transient voltage criteria
4. Discuss the reliability benefits and implications of using a transient voltage response criteria
5. Provide perspective on how to proceed with transient voltage response and transient voltage performance analysis.

This reference document does not provide any position or practices on how to perform or meet NERC Reliability Standards studies or documentation, but it does provide input on how the industry can proceed regarding transient voltage response criteria.

This document does not replace, change, or interpret any requirements in NERC Reliability Standards or other applicable criteria. This Reference Document does not create binding norms, establish mandatory reliability standards, or create parameters by which compliance with Reliability Standards are monitored or enforced. In addition, this Reference Document is not intended to take precedence over any regional procedure. It is recognized that individual Planning Coordinators and Transmission Planners may use alternative and/or more specific approaches that they may deem more appropriate for their planning purposes.

1.2 Definitions

The following definitions are used throughout this paper and defined here for clarity:

- Fault-Induced Delayed Voltage Recovery (FIDVR): the phenomenon whereby system voltage remains at significantly reduced levels for several seconds after a transmission, subtransmission, or distribution fault has been cleared. This condition is characterized by[1]:
    - Stalling of induction motors
    - Initial voltage recovery after the clearing of a fault to less than 90 percent of pre-contingency voltage
    - Slow voltage recovery of more than two seconds to expected post-contingency steady-state voltage levels

[1] NERC, "A Technical Reference Paper – Fault-Induced Delayed Voltage Recovery", http://www.nerc.com/docs/pc/tis/FIDVR_Tech_Ref%20V1-2_PC_Approved.pdf

The following definitions of types of load loss come from the NERC Glossary[2]:

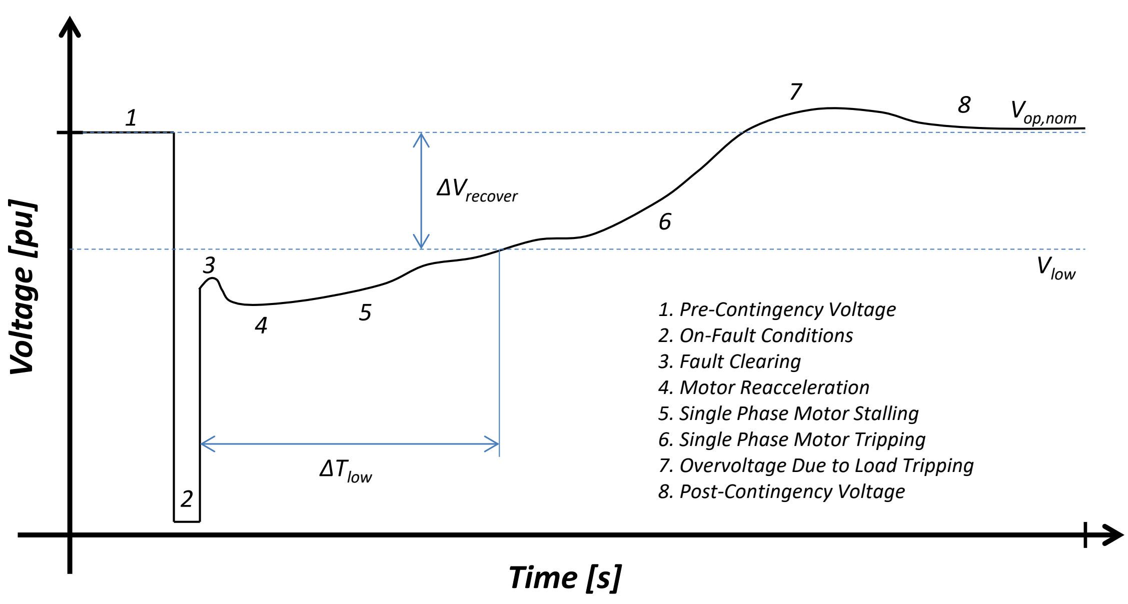
- Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
- Non-consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

The following subsections differentiate between two distinct types of transient voltage response – transient voltage dip and transient voltage recovery.

1.2.1 Transient Voltage Recovery (i.e. recovery from fault)

Transient Voltage Recovery is the transient voltage response following fault clearing. Transient voltage recovery may be delayed due to deceleration and possibly stalling of induction motors (primarily single phase residential air conditioners), where the increased consumption of reactive power causes voltages to remain depressed following fault clearing for a period of time. A delayed voltage recovery event is commonly called Fault Induced Delayed Voltage Recovery (FIDVR). Transient Voltage Recovery time (ΔT_{low}) is often measured as the time from fault clearing to the time in which voltages return to a predefined level V_{low} (e.g. 0.70 pu). Figure 1-1 illustrates this phenomenon and definition.[3]

Figure 1-1 Transient Voltage Recovery



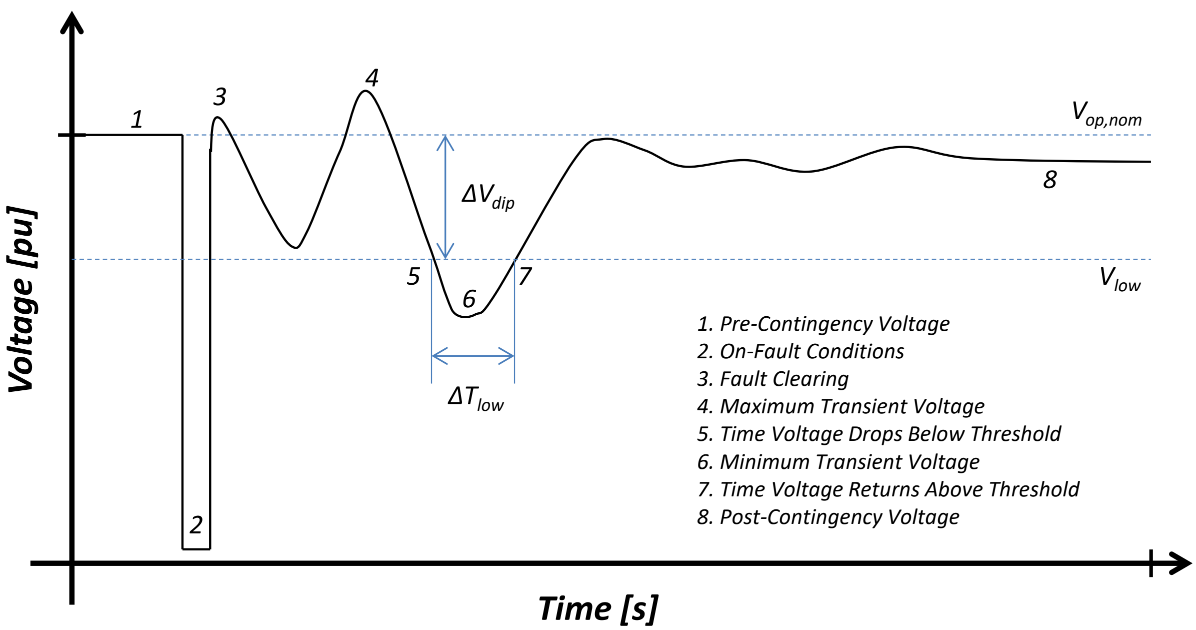
[2] NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf

[3] Recovery time can also be measured from the beginning of the fault, e.g. in PRC-024-1. Low voltage can also be defined as a drop from pre-fault voltage (e.g. 30% voltage drop) instead of an absolute voltage level (e.g. 70% voltage).

1.2.2 Transient Voltage Dip (i.e. sag, swing)

Transient Voltage Dip is a transient response in which voltages dip below specified values for a given time period. This phenomenon is mainly attributed to the oscillatory behavior of a large interconnected power system that results in large transient voltage deviations following a severe contingency (e.g. loss of significant generation or transmission). The characteristics of transient voltage dip are generally measured as shown in Figure 1-2. Unlike transient voltage recovery, transient voltage dip can be measured any time after fault clearing, and may not occur on the first transient swing.

Figure 1-2 Transient Voltage Dip



2 Transient Voltage Criteria – Past

Before the recent activity in the areas of FIDVR and dynamic load models, a number of utilities and regions in North America had transient voltage criteria for other reasons.

2.1 Inter-Area Stability (Margin)

2.1.1 Traditional WECC Voltage Dip Criteria

Since the early 1990s, WECC has used the transient voltage criteria shown in Figure 2-1 and Table 2-1 below. The criteria were designed to avoid uncontrolled loss of load. At the time of development, electronic equipment such as computers were considered the most sensitive loads and these voltage deviation limits were intended to keep them from tripping.

The allowable transient voltage dips were selected for NERC and WECC disturbance category A, B, C, and D. It was intended that no load be lost due to voltage dips for levels A through D disturbances, with some margin at the higher level and little or no margin at the lower level.

Figure 2-1 Traditional WECC Transient Voltage Dip Curve (1993)

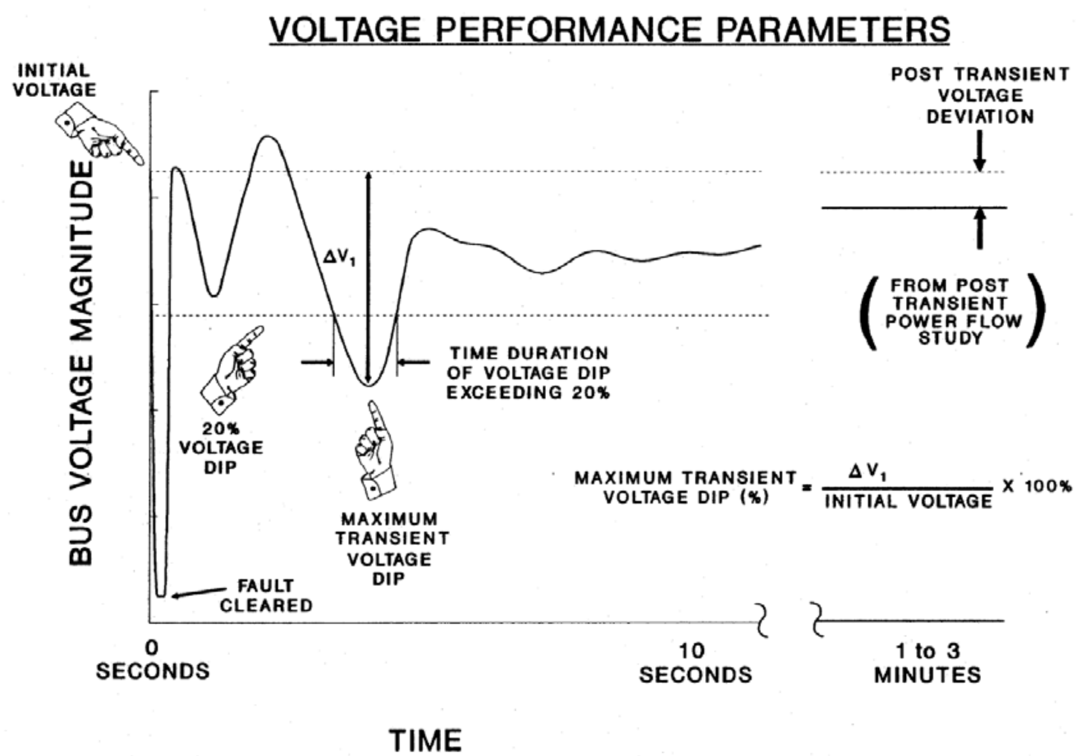


Table 2-1 WECC Disturbance-Performance Table of Allowable Effects on Other Systems

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (outage/year)[1]	Transient Voltage Dip Standard
A	Not Applicable	Nothing in addition to NERC.
B	> = 0.33	Not to exceed 25% at load buses or 30% at non-load buses. Not to exceed 20% for more than 20 cycles at load buses.
C	0.033 – 0.33	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.
D	<0.033	Nothing in addition to NERC.

[1] The outage rates were indicated together with the NERC and WECC disturbance category, and used for performance level adjustment.

2.1.2 Traditional MAPP Criteria

The MAPP region has traditionally used transient voltage criteria to provide some margin to angular instability. The MAPP transmission system carries significant power transfers over long distances, including numerous HVDC lines. Hydro generation in northern Manitoba and coal generation in North Dakota are shipped over AC and DC lines to the Twin Cities of Minnesota and beyond. Even with a traditional ZIP load model, deep voltage dips can occur following faults on major 765 kV, 345 kV, and HVDC transmission lines. Post-fault voltage limits of 70% to 120% for most buses help ensure that the transmission system can handle the levels of power transfers contemplated in the base cases. These voltage dips are mainly caused by power swings following major contingencies.

2.1.3 Traditional ERCOT Criteria

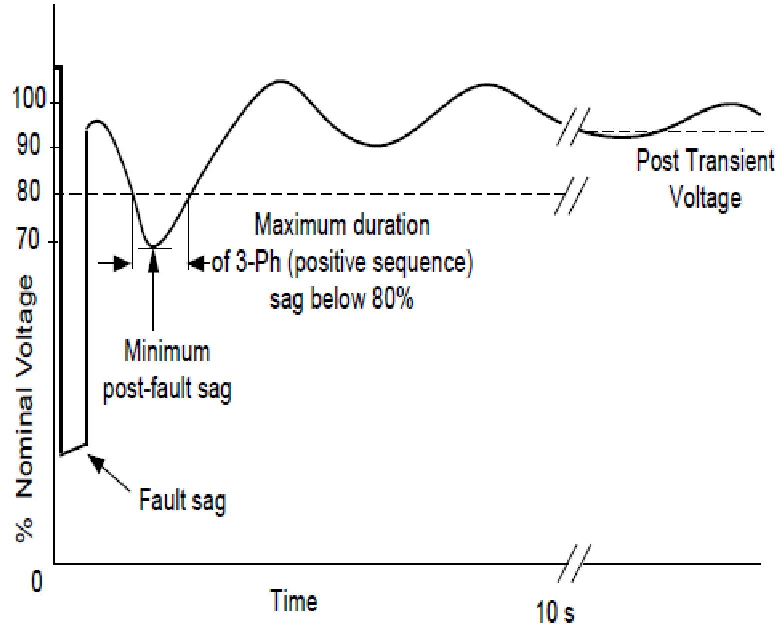
The traditional ERCOT criteria for transient voltage response required that voltages recover to 0.90 p.u. within 10 seconds of clearing the fault.

ERCOT's new voltage recovery standard approved in late 2014 keeps this requirement for NERC categories P2 through P7. For NERC category P1, the new ERCOT standard requires that voltage recover to 0.90 p.u. within 5 seconds of clearing the fault.

2.1.4 Traditional ISO New England Criteria

ISO New England provides a Voltage Sag Guideline in Appendix E of the Transmission Planning Technical Guide. The intent of this voltage sag criteria is to avoid uncontrolled significant load shedding which may lead to unintended system performance, such as widespread system collapse. The criteria in the ISO-NE guidelines document is stated as: "The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage and must not exceed 250 milliseconds below 80% of nominal voltage within 10 seconds following a fault." These criteria are depicted in the figure below.

Figure 2-2 Traditional ISONE Transient Voltage Sag Curve



ISO-NE's criteria is a type of transient voltage dip criteria, which is mainly attributed to phenomena associated with the oscillatory behavior of a large interconnected power system that results in large transient voltage deviations following a severe contingency (e.g. loss of significant generation or transmission).

3 Transient Voltage Criteria – Present

3.1 Drivers and Considerations

3.1.1 NERC Standard TPL-001-4

NERC Reliability Standard TPL-001-4, Transmission System Planning Performance Requirements, introduces the use of dynamic load models, particularly for induction motor load, into the Transmission Planning Standards. The following locations in the standard directly discuss the use of dynamic load models:

- *Requirement R2.4.1*: *"System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable."*
- *Requirement R2.4.3*: *"… Load level, Load forecast, or dynamic Load model assumptions. …"*

Furthermore, the dynamic load model can have a larger impact on the requirements in the standard; the following elements of the standard also impact the use of dynamic load models:

- *Requirement R4.3.1: "Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:"*
    - *Requirement R4.3.1.1*: *"Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized."*
    - *Requirement R4.3.1.2*: *"Tripping of generators where simulations show generator bus voltages or high side of the GSU voltage are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made."*
    - *Requirement R4.3.1.3*: *"Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models."*
- *Requirement R5*: *"**Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.**"*
- *Requirement R6*: *"Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."*
- Table 1: Steady State & Stability - item b. *"Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0."*

Requirement R5 listed above requires the definition of transient voltage criteria. Enforcement for R5 begins January 1, 2016. Recent NERC interpretation has stated that assessments **begun after** this date must include transient voltage criteria. Measure M5 requires documentation of the transient voltage criteria:

> M5. "Each Transmission Planner and Planning Coordinator *shall provide dated evidence* such as electronic or hard copies *of the documentation specifying the criteria for* acceptable System steady state voltage limits, post-Contingency voltage deviations, and *the transient voltage response* for its System in accordance with Requirement R5. [Emphasis (italic) added]"

3.1.2 Generator Requirements and NERC Standard PRC-024-1 (generator voltage and frequency ride-through)

Low voltages and their impact on the reliability of the bulk electric grid are particularly critical at generating stations. Synchronous generators provide the majority of primary voltage control and reactive support to the transmission system and its loads, and ensuring these facilities operate correctly for specified voltage levels is important. NERC PRC-024-1, *Generator Frequency and Voltage Protective Relays Settings*, *"ensures that Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions."*

Requirement R2 pertains to generator voltage protective relaying, stating that:

> *"Each Generator Owner that has generator voltage protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip" zone" of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions:"*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

For PRC-024-1, the point of interconnection is the transmission (high voltage) side of the generator step-up (GSU) or collector transformer.

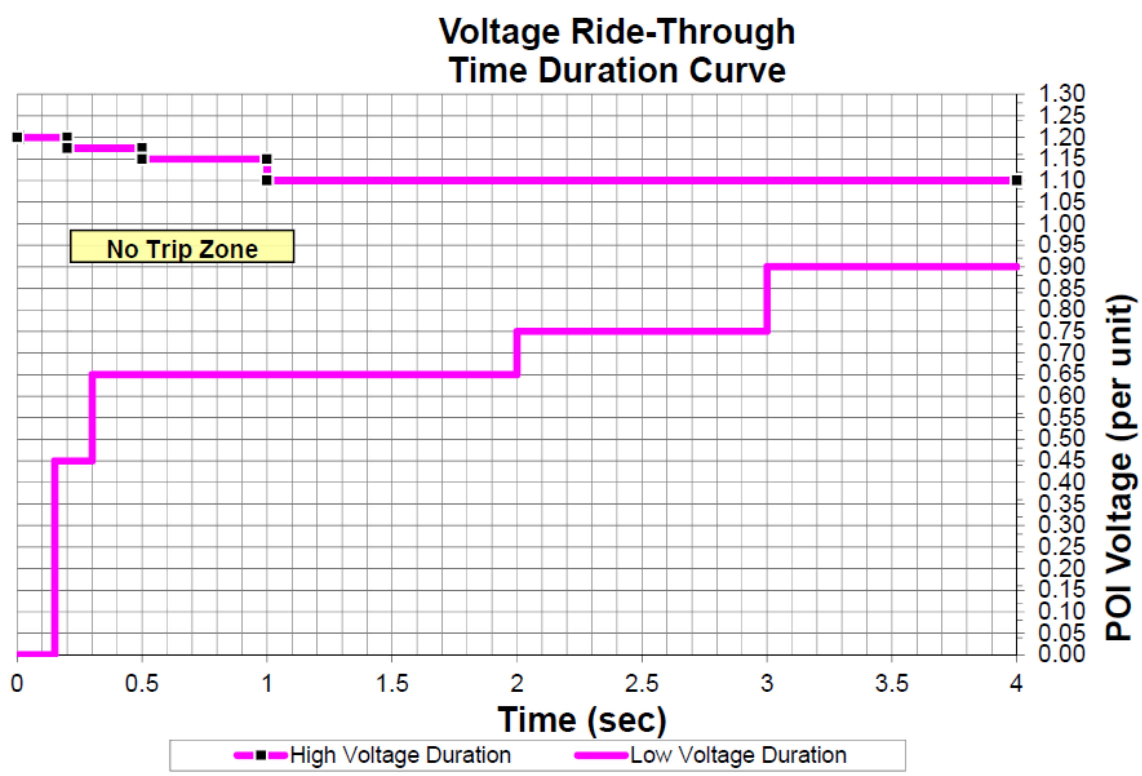
Note that there are other modes of plant or unit under-voltage (UV) tripping, specifically UV tripping of critical auxiliary load caused by UV auxiliary bus protection and contactor drop out of critical equipment that leads to tripping of units. These trip modes are outside the scope of PRC-024. PRC-024 is not an assurance that generation will not trip in the no-trip zone of Attachment 2.

As renewable generation is becoming a larger portion of the total energy supply, voltage and frequency ride-through for renewable plants has become important as well. Renewable plants such as wind and solar traditionally used sensitive voltage and frequency trip settings to drop off-line at the slightest disturbance, per IEEE 1547, which was intended to apply to distribution-connected generation. However, FERC Order 661A and NERC Standard PRC-024-1 now require large, transmission-connected renewable generating plants to ride-through disturbances similar to traditional synchronous generators. Losing large amounts of any type of MW source can cause significant harm to the electric grid and should be avoided.

The Voltage Ride-Through Time Duration Curve in PRC-024-1 Attachment 2 is shown in Figure 3-1. Table 3-1 provides a tabular form of high- and low-voltage ride-through requirements[4].

NERC PRC-024-1 becomes enforceable on 7/1/2016.

Figure 3-1 NERC PRC-024-1 Voltage Ride-Through Curve



[4] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-024-1&title=Generator Frequency and Voltage Protective Relay Settings&jurisdiction=United States

Table 3-1 NERC PRC-024-1 Voltage Ride-Through Thresholds

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

3.1.3 Distribution-connected Generation

Generating resources connected at the distribution level, such as Distributed Generation (DG), are typically not subject to FERC jurisdiction and NERC Reliability Standards. However, voltage and frequency ride-through requirements for DG are becoming more critical as DG becomes a larger portion of the energy supply. Loss of hundreds of MW of DG following a grid voltage or frequency disturbance could add more stress to an already severe event.

IEEE Standard 1547 has traditionally required strict trip settings for DG. However, the standard is being updated to allow extended ride-through for voltage and frequency disturbances, similar to NERC PRC-024-1. Utilities may want to consider applying NERC PRC-024-1 standards to distribution-connected generation as it becomes a more significant portion of their resources.

3.1.4 WECC White Paper and Proposed Standard

Since the WECC regional criteria were developed, the planning world has changed considerably, not only due to the issuance of multiple reliability standards by NERC intended to prevent Adverse Reliability Impact to the BES but also the development and deployment of the new composite load model in dynamic simulations. WECC is, therefore, reviewing the need for separate regional criteria and, if the criteria are still needed, what changes, if any, may be required in order to accommodate the use of new and more complex load models. As part of this effort, the WECC draft team is developing a white paper on the proposed transient voltage response criteria.

The white paper confirmed advancement made in the WECC 1993 regional criteria when compared to the previous practice but also challenged the foundation or intention of the criteria. The foundation of the criteria was the assumption that *"any load loss, firm, or interruptible, by transient voltage dip would be considered uncontrolled and therefore unacceptable"*, and *"…it was intended that no load be lost due to voltage dips for level A through*

D disturbances." Per NERC standards, load lost due to planned protective system action is consequential load loss and may be tripped, and load tripped by customer equipment is excluded from the non-consequential load loss definition and is not prohibited. The main premise for the traditional voltage dip criteria was unfounded.

The WECC draft team is continuing to work on recommendations.

3.1.5 Consequential vs Non-consequential Load Loss

When setting Transient Voltage Criteria, the distinction between Consequential Load Loss and Non-Consequential Load Loss is critical for compliance purposes. Consequential and Non-Consequential Load Loss are defined in the NERC Glossary of Terms[5] as follows:

- Consequential Load Loss – All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
- Non-consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

It might seem logical that *Non-consequential Load Loss* would be any load loss that is not included in the definition of *Consequential Load Loss*. However, the NERC definition of Non-consequential Load Loss is not Consequential Load Loss **plus** some other things. This distinction is confusing to some.

The NERC definitions imply that three types of load loss are acceptable:

1. Consequential Load Loss – as defined above
2. The response of voltage sensitive Load
3. Load that is disconnected from the System by end-user equipment

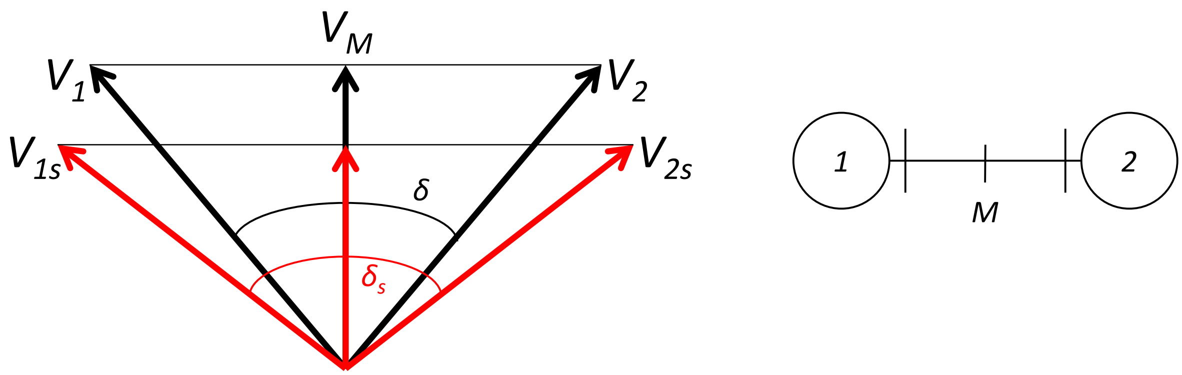
When setting Transient Voltage Criteria, it is recommended that any assumptions and interpretations made by the utility engineer regarding the types of load loss that are and are not considered acceptable be fully documented.

3.1.6 Margin for Stability

Larger transient voltage swings are prone to occur at the midpoint of an oscillatory mode related to local or inter-area generator rotor angle oscillations. A two-area or two-bus system illustrates this nicely, as shown in Figure 3-2. Assuming bus voltage magnitudes are fixed at nominal voltage for each generator and the angle difference between Generator 1 and Generator 2 advances, the midpoint voltage magnitude will drop. This transient drop in voltage can result in transient voltage and angular instability, and Transient Voltage Dip criteria are used as a measure of ensuring sufficient transient voltage support is available in specific locations.

[5] NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf

Figure 3-2 Voltage Vectors for Two-Machine Example



3.1.6.1 Other Methods to Ensure Margin (MW transfer margin, clearing time margin, fault admittance, fault severity?)

A transient voltage dip criterion may not always be a good measure of transient stability margin. The point of lowest voltage may not occur at a bus, and there is non-linearity associated with voltage magnitude. If transient voltage criteria are not used to provide some margin to angular instability, other methods are needed. There are many methods available, such as:

- Add margin to fault clearing time – If a fault is expected to clear in say four cycles, it could be simulated as lasting for 5 or 6 cycles.
- Increase fault severity – For fault categories where the criteria require simulation of single phase to ground faults, the faults could instead be modeled as two-phase to ground faults. Or, the single phase fault admittance could simply be increased by a standard percentage, e.g. 50% or 100%.
- MW Transfer Level – Once the marginally stable MW transfer level is determined, the operational limit could be set to a lower value, e.g. 95% of the marginal transfer level.

3.1.7 Recovery Start Time – During Fault versus After Fault Clearing

If the purpose of transient voltage criteria is to prevent tripping of generation or load, the time period when the fault is active needs to be considered in the transient voltage criteria recovery time. The generators, loads, and their protection devices do not know or care why the voltage is low - whether it is because a fault is currently on the system or decelerating and stalling motors are pulling the voltage down or any other reason. NERC PRC-024-1 voltage ride-through requirements specifically include the fault-on period for this reason. They are intended to make sure generators stay on-line during and after three-phase normally cleared faults and single-phase breaker-failure faults. Ensuring that generators remain on-line to serve the load provides reliability to the grid during and following disturbances.

However, if the purpose of a transient voltage criteria is to minimize or reduce the impact of motor stalling, then the on-fault time might not be included. In this case, the recovery timer should start immediately following the fault clearing. Time to recovery then directly reflects transient behavior inclusive of motor stalling characteristics and their impact on voltage.

Lastly, if the purpose of transient voltage criteria is to help ensure angular stability, only considering the time after fault clearing may be appropriate. The depth of the voltage dip after fault clearing is one indicator of proximity to instability as described in previous sections.

A clearer differentiation between what is trying to be captured within the transient voltage criteria is required. In addition, it may be advantageous to distinguish between generator bus voltages and load bus voltages. It seems intuitive that generator bus voltages should be within the criteria specified in PRC-024-1 while load buses could have a different criteria more focused on post-fault recovery magnitude and duration. Criteria specific to load buses needs to account for the impacts of consequential tripping due to protection and controls on the load side.

When and how recovery start time should be applied becomes difficult when considering reclosing and the potential for reclosing into a fault causing additional motor stalling. This is discussed in more detail in the following section.

3.1.8 Reclosing Implications

Many transmission line protection schemes use automatic reclosing, either instantaneous, delayed, or both. The idea is that the cause of the fault arc, such as a lightning strike, bird, kite string, or swaying tree, may exist only transiently. De-energizing the line may eliminate the arc, and the line may be brought back into service without human intervention. These examples would be called temporary faults. On the other hand, the fault may be permanent, e.g. tree on line, conductor on ground, or compromised insulator. After opening for the initial fault, a reclosing scheme will try to reclose one or both ends of the line to see if the fault was temporary or is permanent. If the fault is still on, the breakers will open again. The number of reclosing attempts can vary from zero to three.

The timing of reclosing varies as well. Sometimes reclosing may be "instantaneous", where the delay is set as short as possible, while still giving ionization time to dissipate in the breaker and the fault. Sometimes one end of the line may reclose instantaneously, while the other end has a longer delay. The end of a line at a generating plant may have "sync check," where it will reclose only onto a hot line. In that case, it would be dependent on the far end successfully reclosing first.

For simulations performed by transmission planners, only high-speed or short-delay reclosing is typically simulated. Longer reclosing delays (e.g. 15 seconds or more) are rarely considered.

For permanent faults, reclosing will cause a second low-voltage event similar to the first. A question to be addressed in transient voltage criteria is whether or not the time outside the voltage limit is reset with each reclosing event or accumulated across all reclosing events in a single simulation. If the time is accumulated, violations are more likely.

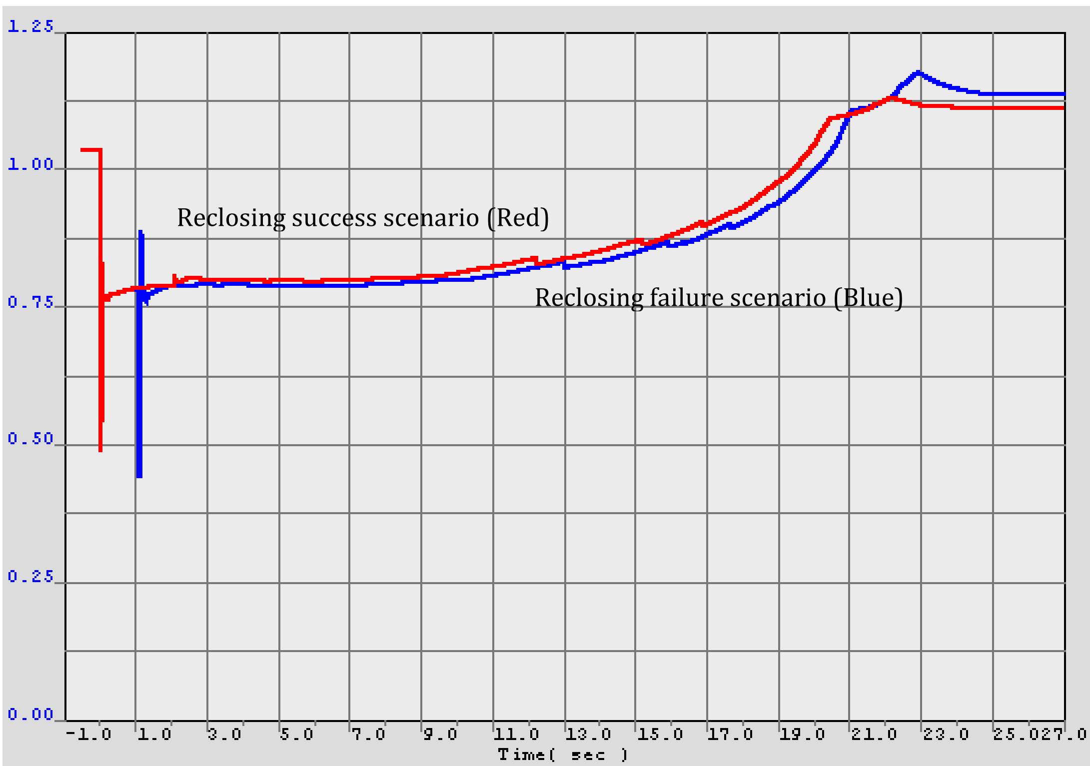
One option is to say that if the voltage fully recovers above all criteria before the second fault (i.e. the first reclose), then the timers are reset. When reclosing onto the fault, the timers would start again at zero. On the other hand, if, at the time the second fault goes on, any voltages are still below criteria, then the timers are not reset and continue to accumulate during and after the second fault.

PRC-024-1 does not address its applicability to reclosing onto permanent faults.

3.1.8.1 Example Reclosing Practices

Figure 3-3 shows the simulation results of two high-speed reclosing scenarios. The WECC composite load model was used in the study. A single-phase to ground fault was applied at time 0 in both scenarios. The red line shows the load bus voltage where the reclosing was performed successfully at 2 seconds, while the blue line shows the load bus voltage where the reclosing wasn't successful at 1 second which resulted in another normal fault clearing where the fault was originally applied. It can be seen that the voltage recovery showed similar recovery response. There is <1-second delay in the voltage recovery and higher post-recovery voltage under the reclosing failure scenario due to the additional air conditioner stalling and motor tripping due to the second fault.

Figure 3-3 Reclosing Simulation Plots



3.2 Surveys of Criteria Currently in Use

The NATF Dynamic Load Modeling Working Group (DLMWG) conducted a survey of its members in the November 2014 to January 2015 timeframe regarding dynamic load modeling and transient voltage criteria.

The NATF DLMWG survey included the following questions on transient voltage criteria:

Table 3-2 Transient Voltage Criteria Survey Questions

TPL-001-4 – Transient Voltage Criteria (Requirement R5)
1. How do you interpret the language in TPL-001-4 R5 "*For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level*"?
a. As a voltage recovery criterion pertaining to the level and duration of recovery from fault disturbances,
b. As a voltage dip criterion pertaining to the level and duration of voltage dips during transient swings
c. Other (please explain)
2. Does your region or company have such a voltage recovery criterion or voltage dip criterion in place?
i. Yes
ii. No
If Yes,
a. What is your voltage recovery criterion?
b. What is your voltage dip criterion?
c. Do you believe the criterion has contributed to reliability?
i. Yes
ii. No
iii. Please explain why you answered Yes or No.
If No,
a. Do you believe there should be criterion in the future for reliability purposes?
i. Yes
ii. No
iii. Please explain why you answered Yes or No

4 Transient Voltage Criteria – Future

4.1 Coordinating Dynamic Load Models and Transient Voltage Criteria

As the industry grapples with dynamic load modeling and transient voltage criteria, the combined choices in these two areas could have a large impact on transmission expansion plans. If dynamic loads are modeled too conservatively, and transient voltage criteria are set too strictly, unnecessary new transmission upgrades may be called for, based purely on those choices. As the industry moves away from a static ZIP load modeling practice, industry engineers should follow the evolving state-of-the-art modeling techniques and model validation methodologies.

Addition of dynamic load models, particularly motors, will definitely add more delay to voltage recovery. In addition, voltage and angle stability do not exist in isolation, and pre-existing voltage dip issues due to power swings will look worse in simulations after addition of dynamic load models. When possible, dynamic load models should be tuned to give simulated responses similar to those seen in actual system events while recognizing that load is highly variable.

While transient voltage recovery criteria at generator buses may be influenced by PRC-024-1, any criteria applied to other buses will need to be coordinated with dynamic load models.

4.2 Effects of Higher Penetration of Renewable Generation

The penetration of renewable generation, particularly wind and solar, is growing rapidly in many parts of North America. Most wind and solar plants use power electronic inverters that perform very differently from traditional synchronous generators. Renewables first evolved as small plants connected to medium voltage distribution systems and were usually required to operate at fixed power factor and trip off-line for most system disturbances (IEEE 1547).

Transmission-connected renewable generation is required to provide reactive power, regulate voltage, and ride through system disturbances like traditional synchronous generators. While they are able to regulate voltage, large renewable plants still do not have a short-term, over-excitation capability like synchronous generators. As synchronous generators are replaced by inverter-based generation, the transient voltage response, inertia, and short circuit ratio may suffer.

Distribution-connected generation, especially inverter-based renewables, is also continuing to grow, and these plants still use the old IEEE 1547 standard. They do not regulate voltage and they trip off-line for many system disturbances. So for a given disturbance, nearby distribution-connected solar plants are likely to trip off-line, and, even if they stay on, they will not provide any voltage support. Distribution-connected generation may need to move toward performance standards similar to transmission-connected plants, although this may require redesign of distribution system voltage control methodologies.

5 Observations, Conclusions, and Recommendations

Observations & Conclusions:

The following observations are made regarding transient voltage response and dynamic load model behavior.

- Motors may stall during low voltages, e.g. during transmission or distribution system faults
- Stalled motors draw more current and reactive power, pulling down voltages for extended periods, up to tens of seconds
- Higher percentages of motors in dynamic load models cause lower voltages and longer recovery time after faults
- Stalled motors will eventually trip, but the time varies from cycles to minutes
- For given transient voltage criteria, higher motor percentages are likely to cause more voltage violations

Based on these observations, the following conclusions are drawn regarding transient voltage response.

- There is not a single correct set of transient voltage criteria.
- The goals of transient voltage criteria should be clearly defined before the criteria can be set.
- Transient voltage criteria and dynamic load models need to be developed in tandem. Their effects on the grid need to be benchmarked before criteria and models are fixed.

Recommendations:

Based on the information collected through the NATF DLMWG survey, current industry standards, inherent dynamic behavior of loads and generation, and current industry practices, the following recommendations are made by the NATF Dynamic Load Modeling Working Group:

1. Transient voltage criteria for generator points of interconnection should consider generator undervoltage relay setting requirements imposed by NERC PRC-024-1 while recognizing that generator undervoltage relays are only one cause of generation loss from low voltage conditions.
2. Individual utilities should be given broad leeway to determine transient voltage criteria for load buses and for buses with no load and no generators.
3. Future NERC Reliability Standards should consider the current state of dynamic load modeling and ensure that the standards in place capture the maturity of this type of modeling. The transient voltage response using one load model may significantly differ from the response using another load model.
4. Future NERC Reliability Standards should more explicitly define what is being asked in terms of a transient voltage *recovery* or transient voltage *dip* criteria.
5. Further research is needed to fully represent the dynamic behavior of loads, particularly induction motor loads and load device internal or self-protection

tripping, in transient stability programs used by Transmission Planners. Utilities and regulatory entities need to stay updated on these efforts and how modifications to the models used by Planners can affect system impact studies.

6. To cope with the increasing number of studies to be performed by Transmission Planners, not only due to transient voltage criteria issues, high performing computing techniques (e.g. parallel processing, cloud computing) may be advantageous as supplements to simulation tools.

6 Appendix- Solutions to Violations of Transient Voltage Criteria

While historical FIDVR events have been identified at key locations across the North American power grid, modeling of induction motor dynamic behavior in positive sequence stability programs is still an evolving subject. Therefore, it is imperative that sensitivity studies be performed to understand the drivers of a delayed voltage recovery event using multiple model parameters and model types.

Regardless, if the defined level of transient voltage response is deemed inadequate, it is also important to understand the mechanisms in which this reliability risk can be mitigated. The following list of solution options provides some background and perspective on this topic.

Synchronous Condenser

A synchronous condenser is a device identical to a synchronous motor whose shaft is not connected to anything but spins freely. Its purpose is to adjust or maintain voltage on the electric power transmission grid. It can generate or absorb reactive power as needed to adjust the grid's voltage, or to improve power factor, with the ability to produce up to 150% of rated MVA in a short-term (few seconds) time frame. Synchronous condensers produce no switching transients and no electrical harmonics. They will not produce excessive voltage levels and are not susceptible to electrical resonances.

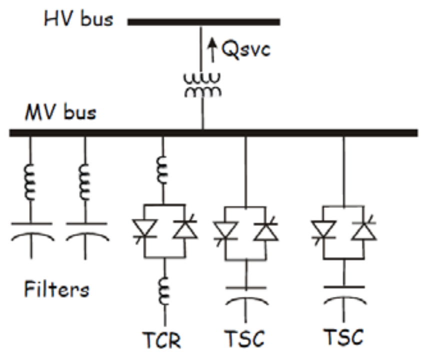
Unlike a capacitor bank, the amount of reactive power from a synchronous condenser can be continuously adjusted. Reactive power from a capacitor bank decreases when grid voltage decreases, while a synchronous condenser can increase reactive current as voltage decreases. However, synchronous machines have higher energy losses than static capacitor banks. Most synchronous condensers connected to electrical grids are rated between 20 MVAr (megavars) and 250 MVAr. Synchronous condensers may be prone to higher maintenance.

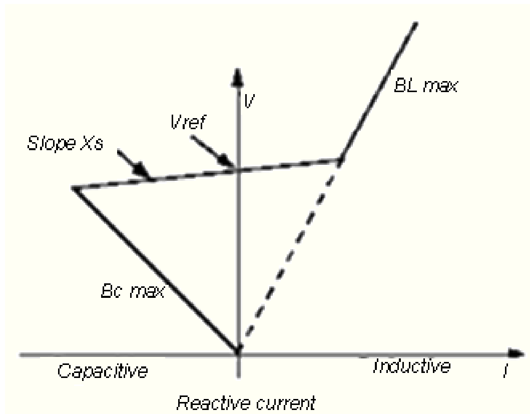
The kinetic energy stored in the rotor of the machine can help stabilize a power system during short circuits or rapidly fluctuating loads such as electric arc furnaces. Synchronous condensers inherently improve the inertia of the system and short circuit strength to solve weak system issues. Voltage recovery from faults is smoother with synchronous condensers due to their inherent physical properties, with minimal effort required in control tuning.

Static VAR Compensator (SVC)[6]

An SVC is a set of AC shunt reactive devices, which generally includes a fixed shunt capacitor, a thyristor-controlled reactor, and filters. Because of the AC shunt susceptance, the SVC reactive power injection depends on the square of the terminal voltage; therefore, the SVC provides less reactive power capability at lower voltages than the STATCOM, for the same nominal rating. The speed of the SVC is slower than that of a STATCOM and harmonics for an SVC are a bigger concern.

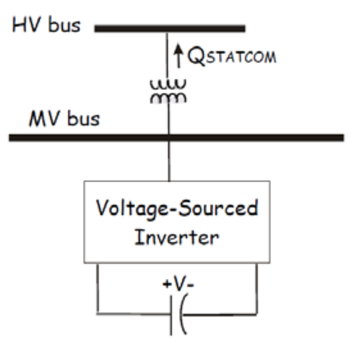
[6] M. Noroozian, C.W. Taylor, "Benefits of SVC and STATCOM for Electric Utility Application," Available: http://www09.abb.com/global/scot/scot221.nsf/veritydisplay/db4151de52e1c959c1256fda00496207/$file/Benefits%20of%20SVC%20and%20STATCOM,%20Sept%202003,%20w%20Taylor.pdf

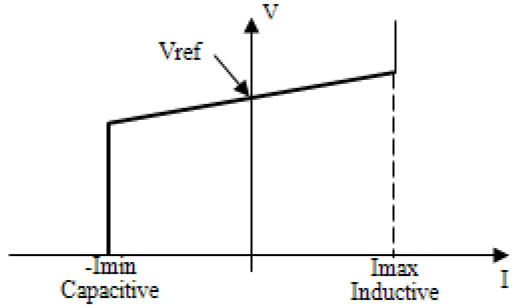




Static Synchronous Compensator (STATCOM)

A STATCOM is a voltage source converter (VSC) device that can act as either a source or sink of AC reactive power injection. Generally, a DC capacitor and power electronic inverter technology controls the terminal voltage of the STATCOM to provide or consume reactive power using very fast switching technology. Because the STATCOM is driven by an independent voltage source, the shunt susceptance, and reactive power injection is linearly proportional to the terminal voltage. A STATCOM is a current-limited device.





Transmission System Modifications

Transmission Infrastructure Expansions

Transmission expansion can improve the strength and voltage performance of a transmission network. While expansions may not mitigate the stalling effect of motor loads, the region of stalling and the subsequent impact of that stalling can be improved.

Transmission Infrastructure Modifications

Conversely, some situations can drive the need to separate or reduce the connectivity of the network to mitigate delayed recovery. For example, following a major delayed voltage recovery event in the Atlanta area, Southern Company determined that operating a transmission line at 230 kV rather than at 500 kV would improve the transient voltage response because this reduced the electrical and geographic area that experiences the low voltage condition caused by the contingency.

Transmission Breaker Reconfiguration

If the contingency under question includes a breaker failure condition (studied as a single line to ground fault), it may be possible to mitigate this through substation reconfiguration or substation upgrades.

However, if additional delayed voltage recovery events for normally cleared three-phase faults at this same location are a concern, then additional breakers or mitigation of breaker failure may not be the best option for mitigating all contingencies defined as a risk.

Distribution Level FACTS Devices

A relatively new technology that is continuing to get attention is the concept of distribution level FACTS devices. These smaller modular devices, generally STATCOMs, can provide fast, dynamic voltage support at the distribution level voltages. A major benefit of these types of events is that the speed of switching could maintain distribution level voltages such that stalling is not experienced for transmission level faults.