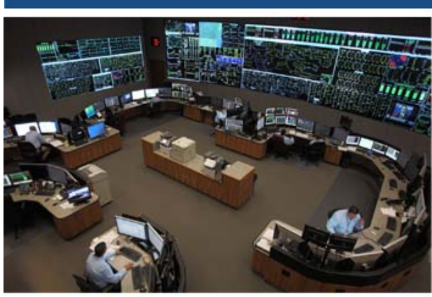
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Reactive Power Planning

December 2016

RELIABILITY | ACCOUNTABILITY

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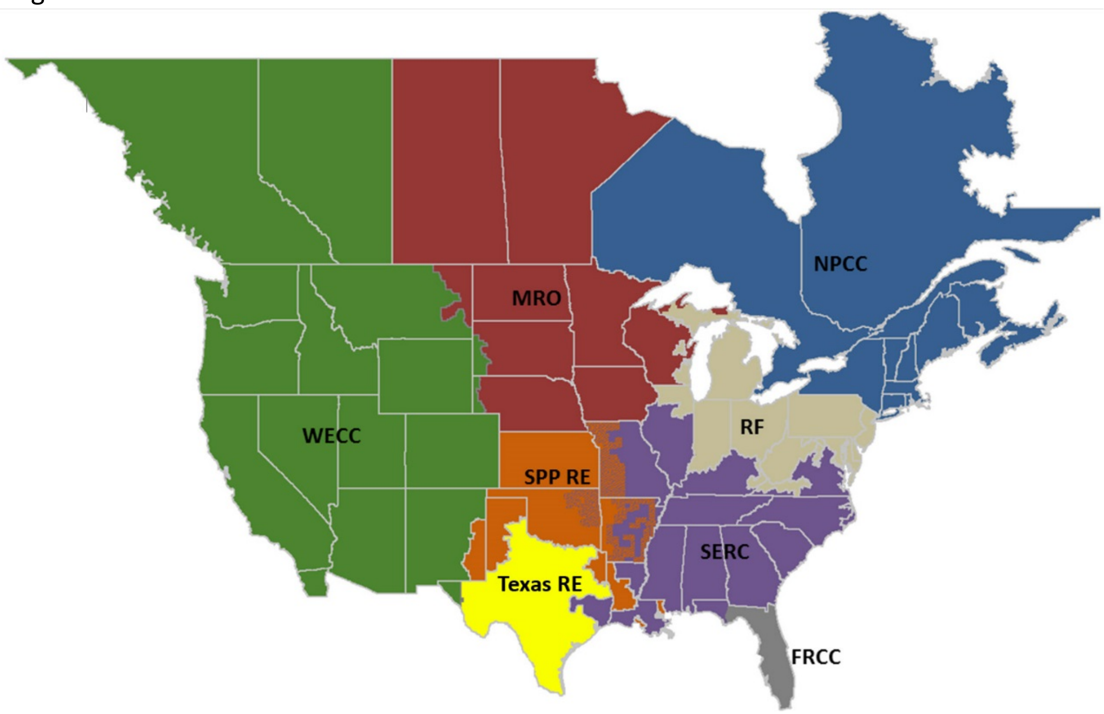
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Preamble

NERC, as the FERC-certified Electric Reliability Organization (ERO),[1] is responsible for the reliability of the Bulk Electric System (BES) and has a suite of tools to accomplish this responsibility, including but not limited to the following: lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis program, the Compliance Monitoring and Enforcement Program, and Reliability Standards. Each entity, as registered in the NERC compliance registry, is responsible and accountable for maintaining reliability and compliance with the Reliability Standards to maintain the reliability of their portions of the BES.

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the BES. The NERC Technical Committees—the Operating Committee (OC), the Planning Committee (PC), and the Critical Infrastructure Protection Committee (CIPC)—are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines per their charters.[2] These guidelines establish voluntary recommendations, considerations, and industry best practices on particular topics for use by users, owners, and operators of the BES to help assess and ensure BES reliability. These guidelines are prepared in coordination between NERC Staff and the NERC Technical Committees. As a result, these guidelines represent the collective experience, expertise, and judgment of the industry.

The objective of each reliability guideline is to distribute key practices and information on specific issues to support high levels of BES reliability. Reliability guidelines do not provide binding norms and are not subject to compliance and enforcement (unlike Reliability Standards that are monitored and subject to enforcement). Guidelines are strictly voluntary and are designed to assist in reviewing, revising, or developing individual entity practices to support reliability for the BES. Further, guidelines are not intended to take precedence over Reliability Standards, regional procedures, or regional requirements. Entities should review this guideline in conjunction with Reliability Standards and periodic review of their internal processes and procedures, and make any needed changes based on their system design, configuration, and business practices.

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1 http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf

2 http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf
http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20(2)%20with%20BOT%20approval%20footer.pdf
http://www.nerc.com/comm/PC/Related%20Files%202013/PC%20Charter%20-%20Board%20Approved%20November%202013.pdf

Executive Summary

This guideline provides strategies and recommended practices for reactive power planning and voltage control and accounts for operational aspects of maintaining reliable voltages and sufficient reactive power capability on the bulk power system (BPS). The purpose of this document is to provide utilities with guidance and direction related to the modeling, study, and placement of reactive power resources in support of robust voltage profiles. The strategies outlined here center around the need for static and dynamic reactive power resource planning and operational planning as described in relevant NERC Reliability Standards. This aligns with NERC's mission of improving reliability through sharing industry practices for planning and operating the BPS and is intended to raise industry awareness and to assist those responsible for planning and operating the BPS in ensuring adequate reactive reserves. This guideline also summarizes FERC Order No. 827,[3] although the information herein is not intended as compliance guidance or as a substitute for parties' independent examination of FERC's Order.

A combination of static and dynamic reactive power resources help ensure grid voltages are planned and operated within predefined limits to maintain system reliability and transfer power reliably across the BPS during normal operations and following a disturbance. These voltage levels are supported by ensuring an adequate and reliable supply of reactive power. Reactive power should be supplied locally because of its dependence on voltage difference. Unlike real power, reactive power cannot be transferred long distances across the BPS. It is usually necessary to site reactive power devices very near to or at the location that is deficient. The type of resource selected to mitigate any reactive power deficiency is driven by the system characteristics. In some situations, static shunt compensation is adequate to alleviate low-voltage conditions. In other situations, dynamic reactive support is necessary to ensure reliable pre- and post-contingency voltage levels and a robust response in voltage following a disturbance.

Planning and operational needs for reactive power may vary significantly across the NERC footprint; however, there are commonalities in the time frames, assessment techniques, processes, and procedures discussed in this guideline. In the planning horizon, sufficient reactive resources need to be planned to meet performance requirements under a wide range of probable contingencies. This results in a system that can be operated reliably over a broad spectrum of system conditions, ranging from summer/winter peak load conditions to the other extreme of light load conditions, such as early morning spring or a fall holiday weekend. In the operating horizon, sufficient reactive resources need to be available for variations in operating conditions, including scheduled and forced outages, to ensure acceptable voltage levels. This is accomplished with automatic controls that provide reactive power to protect equipment and ensure reliability, such as generator automatic voltage control, Flexible AC Transmission System (FACTS) devices, and fast-switched shunt devices. Operator action also helps ensure voltages are within limits by manually switching BPS elements pre- and post-contingency. Both the planning and operational needs help ensure sufficient reactive a reliable BPS

While reactive power planning and operational aspects do have some commonalities, as noted above, the dynamic nature and characteristics of the electrical grid vary between regions. End-use loads can differ drastically in their behavior and performance across parts of the system. Demand levels and power factor can also be significantly different, the electrical networks that feed these loads differ across the system, and the dynamic and reactive power resources available also differ widely. These variations are managed by different planning and operating practices, such as setting appropriate minimum and maximum voltage limits and/or margins. In some areas, steady-state voltage control and/or transient voltage response are of greater concern than in other areas. Due to these inherent differences, the reactive performance of a system should be determined on a more granular sub-system or localized basis. The NERC Reliability Standards define requirements to ensure reliable planning and operation of the BPS, accounting for these similarities and differences. Parties are encouraged to go beyond

[3] Federal Energy Regulatory Commission, Order No. 872, 16 June 2016.
Available: http://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf

requirements in Reliability Standards if it will enhance reliability. The primary standards codifying reactive power requirements in the operations and planning time frames include VAR-001-4.1, VAR-002-4, and TPL-001-4.

This guideline provides a detailed background discussion regarding the reactive characteristics of system components, system reactive behavior, and analytical techniques. The guideline also provides recommended practices for reactive power planning, voltage control, and operational considerations. The appendices provide reactive power planning practices, procedures, and requirements for an array of entities across North America. The information the entities have provided is typical of their practices and philosophies at the time that this guideline was developed. These practices are expected to change and evolve over time.

This Reliability Guideline applies primarily to Planning Coordinators (PCs), Transmission Planners (TPs), Transmission Operators (TOP), Generator Operators (GOPs), Generator Owners (GOs), Distribution Providers (DPs), and Reliability Coordinators (RCs).

Background

This section provides fundamental information describing reactive power and the types of system elements that are able to provide reactive power to the grid in support of system voltages, power transfers, and BPS reliability.

Apparent power is the product of voltage and current. It consists of two components – active power and reactive power. Reactive Power is defined by NERC as:[4]

> "The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influence electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar)."

Active (real) power is the component of apparent power that does real work and is defined as the component of the current in phase with the voltage. Reactive power is produced when the current waveform is out of phase with the voltage waveform due to inductive (current lags voltage) and capacitive (current leads voltage) loads and is measured in volt-ampere reactive (var). Neglecting line resistance (R) and capacitance (B), reactive power transfer across a short transmission line can be expressed as

$$Q_r = \frac{V_r}{X}(V_s \cos\delta - V_r)$$

where V_s and V_r are the sending- and receiving-end voltage magnitudes, respectively, X is the line reactance, and δ (expressed as ϕ_1-ϕ_2 in Figure 1) is the phase angle difference ("power angle") between the two ends of the line (Figure 1). It is clear from this equation that reactive power is a function of voltage difference, angle difference, and electrical impedance; however, angle difference has a relatively small influence while voltage difference and impedance are much stronger drivers. For this reason, voltage control is tightly coupled with reactive power control and vice versa.

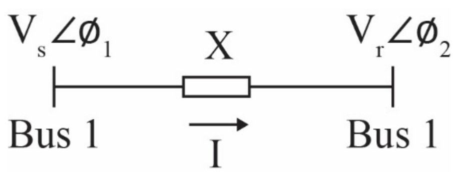

Figure 1: Short Transmission Line

Voltage is supported through the supply of reactive power; hence, reactive power is required to transfer large amounts of active power across the grid for serving the loads. Reactive power is supplied locally, mainly because of its dependence on voltage difference, and it is usually necessary to site reactive devices near or at the location that is deficient in reactive support. Typically, reactive power supply is provided where it is needed to minimize losses. The ability of power system to maintain acceptable voltage at all buses under normal and contingency operating conditions requires sufficient reactive resources.

Reactive power resources are generally differentiated between static and dynamic resources and are usually defined by reactive power output controllability once connected to the grid:

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

- **Dynamic reactive resources** adjust reactive power output automatically in real-time over a continuous range within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set point voltage or operate in a voltage droop mode. Many dynamic reactive resources, particularly newer ones employing power electronics, can respond within electrical cycles using fast-acting controls. For example, Static Synchronous Compensators (STATCOMs) have a response time of around 50 ms.

- **Static reactive resources** have fixed reactive power output at their nominal voltage, and their capability varies according to voltage squared. These devices are switched in or out of service based on system conditions. Switching action can be manual or automatic, but this type of resource provides a fixed nominal contribution of reactive power to the grid once connected.

Static reactive resources generally include the following elements:

- **Fixed Shunt Devices**: fixed shunt reactive devices include shunt capacitors and reactors. These devices have a fixed nominal rating and their reactive power production or consumption is dependent on terminal voltage. While these types of devices are relatively cheap, their operating characteristic and inability to manually switch in/out quickly enough to provide dynamic support limits their applicability to steady-state operation.

- **Switched Shunt Devices:** switched shunt capacitors and reactors are simply fixed shunt devices that have the capability to automatically be switched in service based on control settings or operator action. These devices may have shorter switching times than the fixed shunt devices, but their inability to change reactive power output in real-time differentiates them from dynamic reactive devices.

- **Transmission Circuits:** Transmission lines have an operating characteristic known as the surge impedance loading (SIL), which is the active power loading at which reactive power produced and consumed by the line are balanced. Lines produce reactive power due to their natural capacitance, and the amount produced is dependent on the capacitive reactance (X_C) of the line and the voltage. Lines also consume reactive power due to their inductive reactance (X_L). The SIL occurs when VARs produced equal VARs consumed, defined by

$$VAR_{produced} = \frac{V^2}{X_C}$$

$$VAR_{consumed} = I^2 X_L$$

$$Z_{SI} = \sqrt{\frac{L}{C}}$$

$$SIL = \frac{V^2}{Z_{SI}}$$

Dynamic reactive resources generally consist of one or more of the following:

- **Synchronous Generators**: Synchronous generators are currently the primary source of active power in the electric power system and can provide or consume large amounts of reactive power. This is driven by the excitation voltage provided to the rotor of the machine, similar to a synchronous condenser. Limits on reactive power capability are dependent on stator winding rating, field current rating, terminal voltage rating, and the active power output of the machine. Figure 2 shows a generator capability ("D") curve and the influence active power has on reactive power output capability. Generators consuming reactive power are in leading mode while generators producing reactive power are in lagging mode. The generator excitation limiters are intended to limit operation of the generator to within its continuous capabilities. Generally, the setting of the underexcitation limiter (UEL) will be coordinated with the steady-state stability limit of the generator. The overexcitation limiter (OEL) limits generator operation in the overexcited region to within the generator capability curve. There are examples where reactive power capability can be increased, such as increasing pressure in the hydrogen cooling system, but the excitation limiter should be adjusted to actually utilize that additional capability.

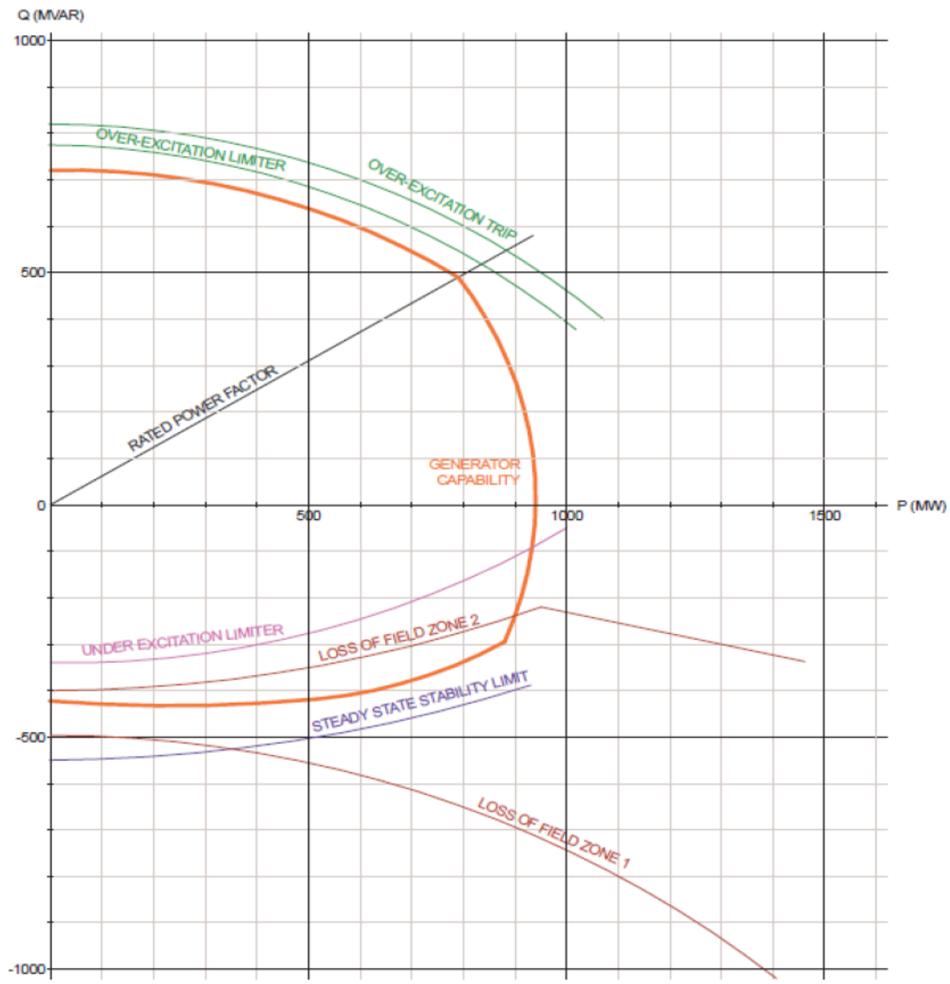

Figure 2: Generator Capability Curve

- **Synchronous Condensers**: A synchronous condenser is a synchronous machine whose shaft is not driven by a prime mover; rather, the shaft spins freely and the field voltage is controlled to produce or consume reactive power by adjusting set point voltage. Thus, this contributes to overall power factor correction or/and local voltage control (Figures 3 and 4). Synchronous condensers have several advantages as they contribute to system short-circuit capacity, have 10-20% overload capability for up to 30 minutes, and provide system inertia.

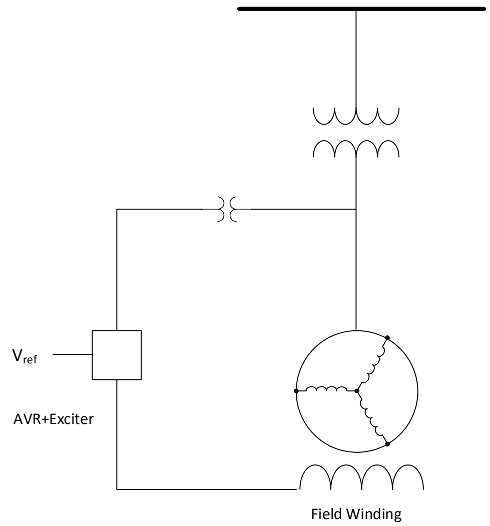

Figure 3: Synchronous Condenser Oneline

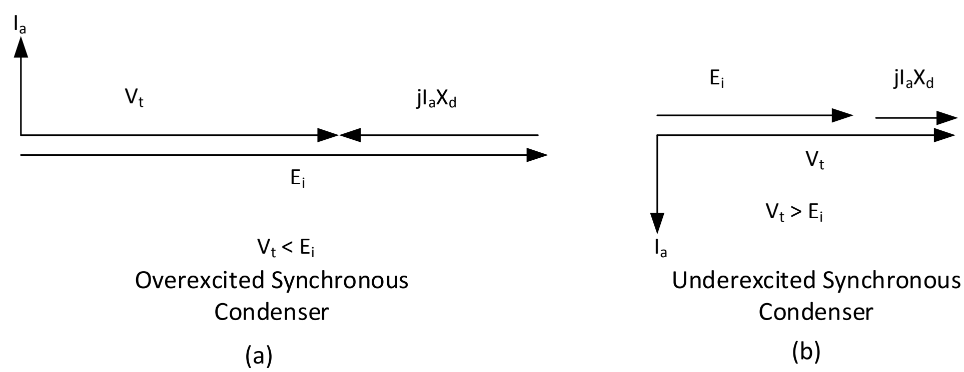

Figure 4: Synchronous Condenser Phasor Diagram

- **Non-Synchronous Generators**: Non-synchronous generators include induction generators (e.g., Type I, II, and III wind plants) and electronically coupled resources (e.g., Type IV wind plants and solar) and they may or may not have the capability to provide reactive power and voltage control. This may change with FERC Order No. 827, discussed below. Interconnection requirements drive the capability of the plant to have reactive capability for voltage control, such as reactive capability to ± 0.95 pf lead/lag. However, the individual units within a plant may not have the capability and additional reactive resources (e.g., small STATCOMs or SVCs) may be required to maintain a power factor or voltage control set point at the Point of Interconnection (POI). A key distinction between non-synchronous and synchronous resources is that non-synchronous reactive capability is not described in terms of a "D-curve". Reactive capability is often based on the number of individual units (e.g., number of wind turbines or photovoltaic panels) online for the plant as well as the plant-level reactive power controls.
- **Static Synchronous Compensators (STATCOM)**: A STATCOM is a voltage source converter[5] (VSC) device part of the Flexible AC Transmission System (FACTS) family that consists of a DC voltage source behind a power electronic interface connected to the AC grid through a transformer. This results in a controllable voltage source and hence reactive power output. A simple configuration and electrical representation of a STATCOM is shown in Figure 5.

[5] A voltage source converter (VSC) is a self-commutated device that synthesizes a voltage waveform with variable magnitude with respect to the system voltage to control the reactive power production and consumption of the device.

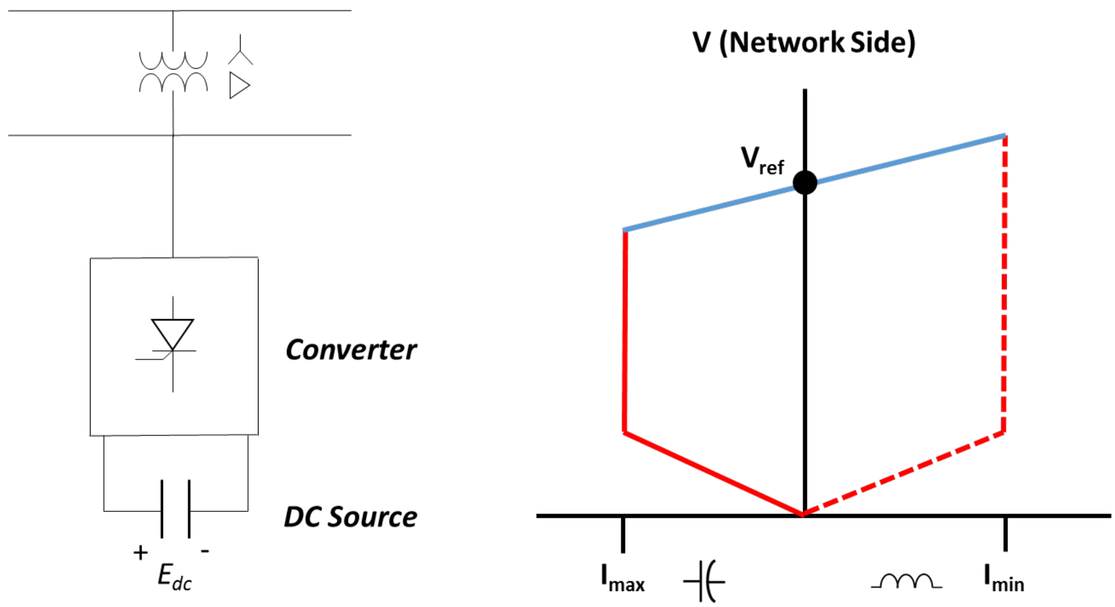

Figure 5: Static Synchronous Compensator (STATCOM) Oneline and Characteristic

- **Static Var Compensators (SVC):** This is a FACTS device that consists of thyristor-controlled reactors (TCRs), thyristor-switched capacitors (TSCs), and fixed capacitors acting as a harmonic filter. The TCR consists of reactors in series with thyristor valves that continuously control the reactive power output by varying the current flow through the reactor. A TSC consists of capacitors, reactors, and thyristor valves that simply switch the capacitor in and out of service. The fixed capacitor is part of the filter that absorbs the harmonics generated by the thyristor switching, supplying a fixed reactive power to the grid. A simple configuration and operating characteristic are shown in Figure 6.

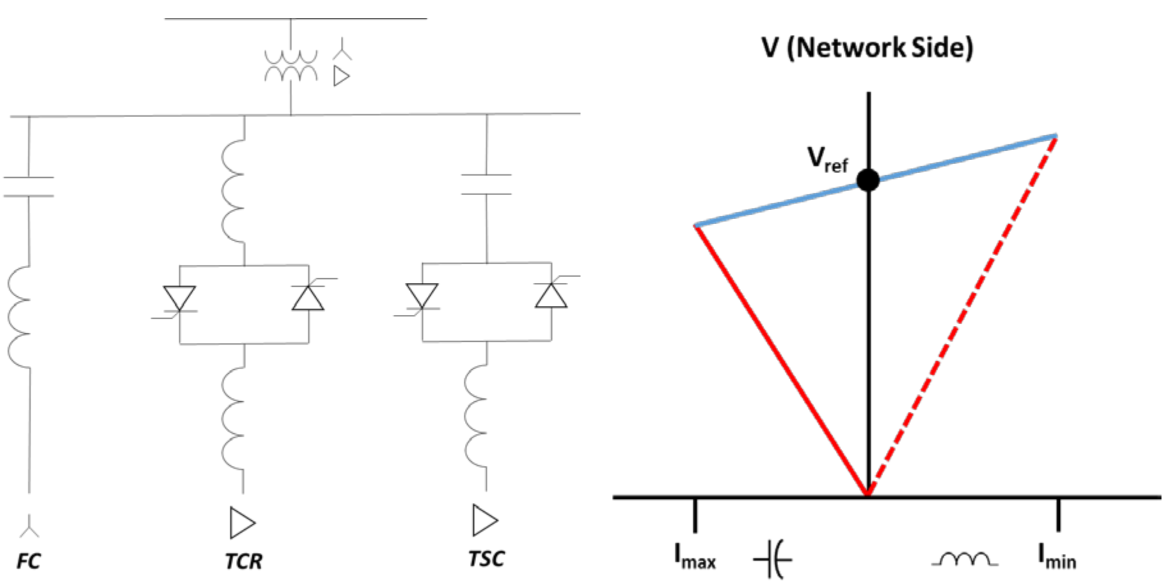

Figure 6: Static Var Compensator (SVC) Oneline and Characteristic

- **Voltage Source Converter (VSC) HVDC**: A VSC HVDC uses a voltage source on the DC side of conversion, enabling direct control of active as well as reactive power output on each end of the converter. Reactive power output takes a constant-current characteristic and is directly proportional to voltage. Reactive power capability tends to decrease as active power increases (similar to a traditional generator D-curve). Figure 7 illustrates the basic configuration of a VSC HVDC circuit. A conventional line-commutated HVDC[6] requires external reactive support.

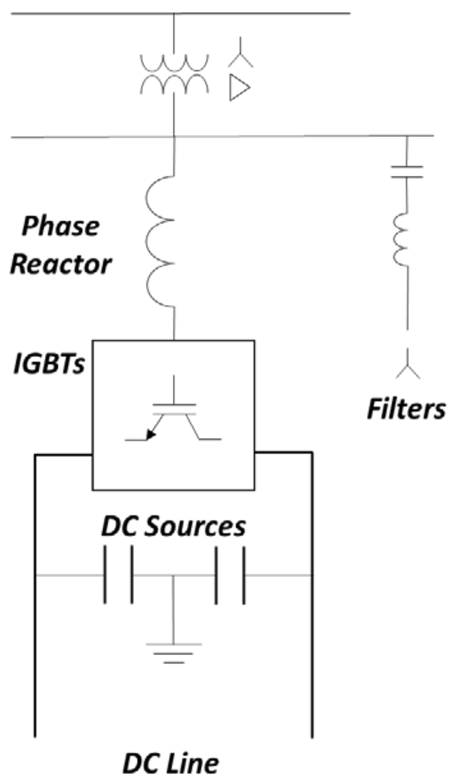

Figure 7: Voltage Source Converter High Voltage DC Circuit Oneline

[6] Conventional HVDC technology uses current-source, line-commutated converters that require a synchronous voltage source to operate. The converters demand large amounts of reactive power, and filters (shunt capacitors and reactors) are required to offset these demands and reduce levels of harmonic current caused by thyristor switching.

Relevant FERC Orders and NERC Reliability Standards

While reactive power planning and operational needs vary significantly across North America based on local system characteristics and practices, NERC Reliability Standards define a minimum set of requirements to ensure reliable planning and operation of the BPS. The primary standards codifying reactive power requirements in the operations and planning time frames include VAR-001-4.1, VAR-002-4, and TPL-001-4. This section summarizes the language and focus of each standard.

VAR-001-4.1 and VAR-002-4 Summary

VAR-001-4.1 sets forth the requirements applicable to TOPs to “ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.”[7] VAR-002-4 sets forth the requirements applicable to GOPs and GOs to “ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.” Generators are the most prevalent Reactive Power resources and play an integral role in maintaining voltage stability on the BPS. Collectively, these Reliability Standards seek to prevent severe voltage deviations, voltage instability, and voltage collapse on the BPS. Entities should review these standards carefully.

To summarize briefly, VAR-001-4.1 addresses the following for each TOP:

- Requirement R1: Specify a system-wide voltage schedule (either a range or a target value with an associated tolerance band) as part of its plan to operate within defined limits; provide the voltage schedule to its RC and adjacent TOPs upon request.
- Requirement R2: Schedule sufficient reactive resources to regulate voltage under normal and Contingency conditions.
- Requirement R3: Operate or direct operation of devices to regulate transmission voltage and reactive flows, as necessary.
- Requirement R4: Develop criteria to allow exemptions for generators from certain requirements related to voltage operations, maintenance, and control, and notify a GOP if its generator satisfies the exemption criteria.
- Requirement R5: Specify a voltage or reactive power schedule (either a range or a target value with an associated tolerance band) for generators at either the high- or low-side of the generator step-up (GSU) transformer; provide the schedule to associated GOP; direct GOPs to comply with that schedule; provide the GOP notification requirements for deviating from schedule; and provide the GOP the criteria used to develop the schedule, if requested.
- Requirement R6: After consultation with GOs regarding changes, communicate step-up transformer tap changes, the time frame for completion, and the justification for these changes to GOs.

To summarize briefly, VAR-002-4 addresses the following for each GOP:

- Requirement R1: Operate each of its generators connected to the transmission system in automatic voltage control mode or in a different control mode as instructed by their TOP[8].

[7] The standard also applies to GOPs within the Western Interconnection (WECC Variance).

[8] Unless exempted by criteria developed in VAR-001-4.1, Requirement R4, or certain notifications are made to the TOP specifying the reason(s) it cannot do so.

- Requirement R2: Maintain the TOP's generator voltage or Reactive Power schedule, unless the GOP is either exempted or complies with the notification requirements for deviation established by the TOP from VAR-001-4.1, Requirement R5;
- Requirement R3: Notify its TOP of a change in status of its voltage controlling device lasting longer than 30 minutes.
- Requirement R4: Notify its TOP of a change in reactive capability due to factors other than those described in VAR-002-4, Requirement R3 and lasting longer than 30 minutes.

Briefly, VAR-002-4 also addresses for each GO:

- Requirement R5: Provide information on its step-up transformers and auxiliary transformers, upon request from the TOP or TP.
- Requirement R6: Comply with the TOP's step-up transformer tap change directives unless such action would violate safety, equipment rating, regulatory requirements, or statutory requirements.

Standards VAR-001-4.1 and VAR-002-4 act in concert to ensure that, in the operational horizon, the BPS operates at acceptable voltage levels and that sufficient Reactive Power is available on the BPS to provide the voltage support necessary to maintain voltage stability.

TPL-001-4 Summary

TPL-001-4 establishes "Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." The standard applies to each PC and TP. Reactive power planning is a critical component of long-term reliability planning and system studies as outlined in a number of the requirements in TPL-001-4. With respect to reactive power planning, TPL-001-4 addresses the following for each PC and TP:

- Requirement R5: Have criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, and transient voltage response for its system. Transient voltage response criteria must specify, at a minimum, a low-voltage level and maximum length of time that transient voltages may remain below that level.
- Requirement R6: Define and document the criteria or methodology used to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding within its planning assessment.
- Requirements R3 (steady state) and R4 (stability): Trip generators in simulations where simulations show generator bus voltages or high-side GSU voltages are less than known or assumed minimum generator steady-state or ride-through voltage limitations. Document assumptions for tripping levels appropriately.
- Requirement R2: Use a dynamic load model that represents the expected dynamic behavior of Loads that could impact the study area while considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.
- Requirement R7: Coordinate responsibilities between the PC and TP(s) with the intent to eliminate confusion regarding the responsibilities of the applicable entities. This ensures that all elements needed for regional and wide-area studies are defined with a specific entity responsible for each element, and that no gaps will exist in planning for the BPS.
- Requirement R8: Share planning assessments with neighboring systems to ensure that information is shared with (and input received from) relevant entities with a reliability-related need that may be affected by an entity's system planning.

FERC Order No. 827: Reactive Power Requirements for Nonsynchronous Generation

FERC issued Order No. 827[9] on June 16, 2016, eliminating the exemptions for wind generators from the requirement to provide reactive power by revising the *pro forma* Large Generator Interconnection Agreement (LGIA), Appendix G of the LGIA, and the *pro forma* Small Generator Interconnection Agreement (SGIA). As a result, all newly interconnecting non-synchronous generators, as defined in the Order, will be required to provide reactive power at the "high-side of the generator substation as a condition of interconnection," starting on the effective date of the Final Order. FERC found that, "[d]ue to technological advancements, the cost of providing reactive power no longer creates an obstacle to the development of wind generation" and this decline in cost results in the prior exemptions being "unjust, unreasonable, and unduly discriminatory and preferential." Entities should review Order No. 827 carefully. This non-binding, informative guideline summarizes some aspects of the Order; however, it is not intended to substitute for review of Order No. 827 as is not intended as compliance guidance. FERC addresses the following items in its Order:[10]

- Power factor range
- Point of measurement
- Dynamic reactive power capability requirements
- Real (active) power output threshold
- Compensation

Power Factor Range

The Commission required that all newly interconnecting non-synchronous generators, as defined in the Order, "design their Generating Facilities to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation. At that point the non-synchronous generator must provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range that applies to all non-synchronous generators in the transmission provider's control area on a comparable basis."[11]

Point of Measurement

Order No. 827 specifies the point of measurement for reactive power provided by non-synchronous generators as the ***high-side of the generator substation.***[12] To clarify this location, the Commissions states:

> "As an example, the generator substation would be the substation for a wind generator that separates the low-voltage collector system from the higher voltage elements of the Interconnection Customer Interconnection Facilities that bring the generator's energy to the Point of Interconnection."[13]

Figure 8 shows an example, created for illustrative purposes in this guideline, of a wind power plant one-line diagram. In the figure, the collector systems aggregate to a generator step-up transformer at the generator substation. The ***high-side of the generator substation*** is marked with a dashed red box. Some arbitrary point is marked on the transmission line, leaving the substation to denote the POI, which may be at or near the high-side, but may also be further down the line as the point of ownership changes from the GO to the TO.

[9] Federal Energy Regulatory Commission, Order No. 872, 16 June 2016.
Available: http://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf

[10] NERC provided comments on the Notice of Proposed Rulemaking (NOPR) preceding this Final Rule.

[11] FERC Order No. 827, FERC Stats. & Regs. ¶ 34 at P. 29.

[12] FERC Order No. 827, FERC Stats. & Regs. ¶ 34 at P. 29.

[13] FERC Order No. 827, FERC Stats. & Regs. Footnote 31 at P. 12.

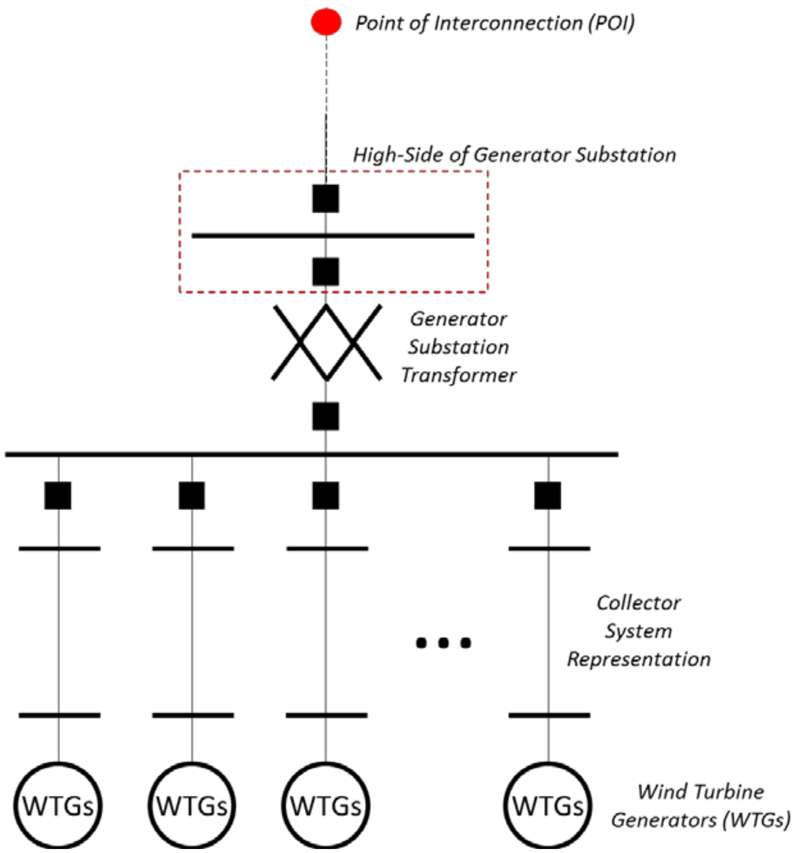

Figure 8: Wind Power Plant Oneline Diagram Example

FERC states that this location is a "middle ground" between measurement points. The first measurement point would be the Generating Facilities where little reactive power would be provided to the transmission system but this would be relatively inexpensive. The other measurement point would be the POI where the full capability would be available to the BPS but would be more expensive to implement.[14]

Dynamic Reactive Capability

FERC Order No. 827 states that "dynamic reactive power capability may be achieved at the high-side of the generator substation at lower cost compared with dynamic reactive power at the Point of Interconnection by systems using a combination of dynamic capability from inverters plus static reactive power devices to make up for losses." Therefore, FERC stated that it would give non-synchronous generators flexibility to:

> "[U]se static reactive power devices to make up for losses that occur between the inverters and the high-side of the of the generator substation, so long as the generators maintain 0.95 leading to 0.95 lagging dynamic reactive power capability at the high-side of the generator substation."[15]

Real (Active) Power Output Threshold

Order No. 827 requires all newly interconnecting non-synchronous generation, as defined in the Order, to meet the reactive power requirements at all active power output levels. FERC notes that modern inverters can be designed to provide this capability and that this will encourage further technological development and treat non-synchronous generation comparably with synchronous generation.

[14] FERC Order No. 827, FERC Stats. & Regs. ¶ 39 at P. 33.

[15] FERC Order No. 827, FERC Stats. & Regs. ¶ 38 at P. 32.

FERC provided an example of a 100 MW generator required to provide 33 MVAR at 100 MW output and 3.3 MVAR at 10 MW output. This is a triangle-shaped capability curve (shown in Figure 9). The green box shows the reactive capability for rated active power output and the blue dashed lines show the decreasing capability at lower active power outputs. FERC's proposed 10% threshold (as shown in the figure) was not used in the Final Order and the lower limit is 0 MW output.

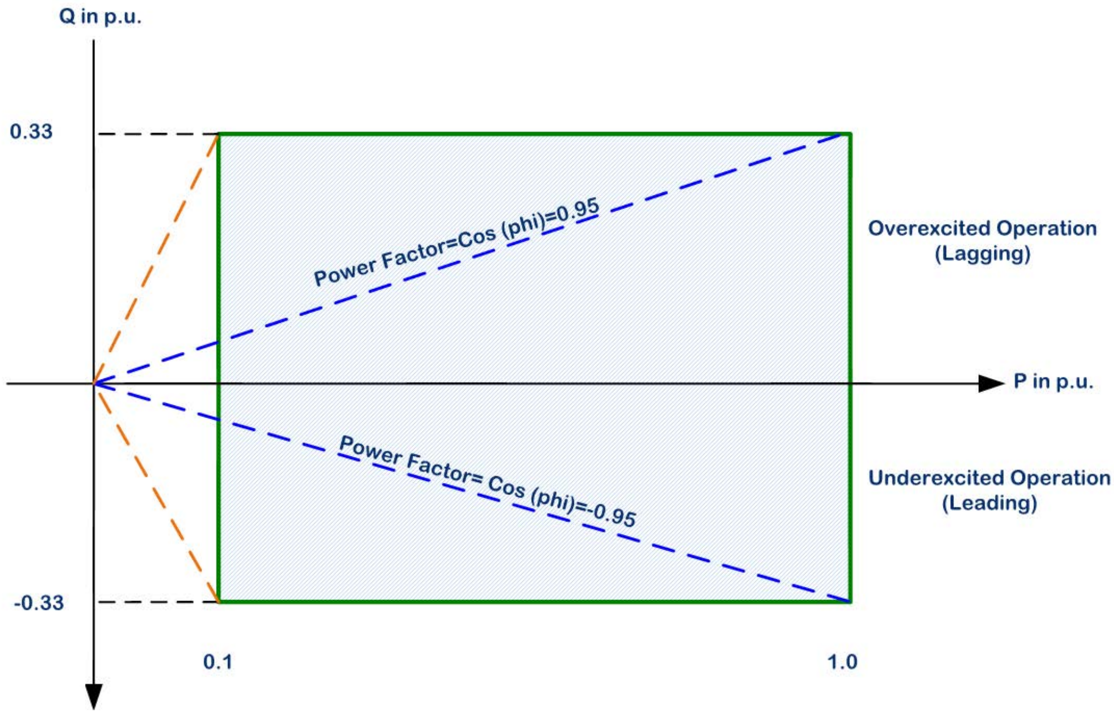

Figure 9: Non-Synchronous Generator Reactive Capability

Reactive Power Analysis Time Frames

Reactive power planning and voltage control can be separated by time frame to better understand system reactive capability requirements. The time frames[16] and the considerations for each are addressed in this section.

Steady-State: Pre-Contingency

In steady-state operation, voltages are maintained within scheduled voltage ranges on the BPS, with individual elements (e.g., generators and dynamic reactive resources) maintaining a terminal voltage set point value. Manual readjustment of network elements is performed to maintain these schedules throughout the day as load and transfer levels change. Automatic devices also continuously operate to maintain their set points. In these conditions, the system is at a planned operating condition in which all facilities are in-service or out-of-service on planned maintenance.[17] The grid is said to be operating in a "secure" state, meaning that there are no existing operating limit violations and analytical tools show no violations of emergency limits following any defined outage conditions. In the event that the analytical tools identify a post-contingency low (or high) voltage, actions may be taken pre-contingency to mitigate this potential future state. This may consist of inserting (or removing) shunt reactive devices on the system. System controls in (modeling) this system condition includes under-load tap changer action (ULTC), automatic action of continuously responding resources, and voltage control modes.

Transient[18]

Following a system disturbance, transient voltage stability may be a concern and is studied using transient stability tools. In this time frame, the following considerations are made:

- Generator automatic voltage regulator (AVR) excitation system response
- AVR over-excitation and under-excitation limiters (where applicable) may come into effect, depending on design
- Generator voltage protective relay settings
- Generator turbine-governor controls, HVDC controls, and other fast-acting FACTS controls effects
- Automatic transformer tap changing is not considered due to their slow controls and intentional time delays
- Automated local or wide-area Remedial Action Schemes (RAS) (e.g., generator tripping, automatic load tripping, line tripping, and other automatic actions) are considered
- Under-Voltage Load Shedding (UVLS) settings
- Dynamic load characteristics including the effects of induction motor loads

In this time frame, dynamic reactive resources to sustain transient voltage support during the natural swings of the system are crucial. Figure 10 explains why voltage support, particularly in the middle of interconnected systems is critical. As power transfer between areas (and during power swings) increases, the angle difference between the areas (δ) increases. Assuming the voltage minimally fluctuates at each end due to generator terminal voltage controls, it is clear that the midpoint voltage magnitude, V_M, will change (decrease) when that angle difference increases. As the two ends of the system swing in terms of angle difference and power transfer, voltage magnitude also oscillates greatest at the midpoint. For this reason, transient voltage stability is generally a concern for systems with long transmission lines and high transfers between interconnected areas.

[16] These time frames vary based on dynamic behavior, system configuration, planning procedures, etc.
[17] Also assuming that any pre-existing forced or unplanned outages have been dealt with.
[18] Typically 0 – 3 seconds.

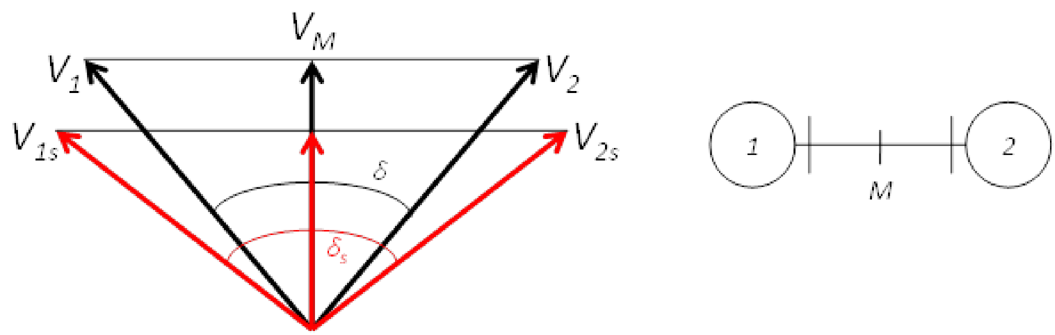

Figure 10: Two-Area Vector Diagram – Voltage Oscillations

While pre-contingency voltages can be maintained using static reactive resources,[19] this time frame focuses primarily on dynamic reactive capability due to the transient nature of large power and voltage swings and the short response time required. It is important to differentiate between two distinct transient voltage responses:

- **Transient Voltage Dip:** voltage dips or sags caused by inter-area or local oscillations that result in large changes of active and reactive power flow and subsequently voltage.
- **Delayed Voltage Recovery:** delayed recovery of voltage primarily due to Fault Induced Delayed Voltage Recovery (FIDVR)[20], and stalling and reacceleration of induction motor load that results in large draws of reactive power.

Figure 11 illustrates the fundamental difference between transient voltage dip events and delayed voltage recovery events. Transient voltage dips are a result of large power swings where significant voltage deviations can occur during the dynamic response of the grid to a major system event. This response is driven by inter-area transfer levels, system dispatch, dynamic reactive resources available, and system topology. FIDVR-type delayed voltage recovery events are driven by end-use load behavior and load composition caused by voltage sags from faults. Generally, FIDVR events are relatively localized within the transmission network rather than a wide-area response. Modeling delayed voltage recovery events is driven predominantly by the dynamic load model used and the capability to represent motor load(s) and stalling of induction motors. Appendix B provides transient voltage response criteria for operating entities across the interconnections, as required per TPL-001-4 Requirement R5.

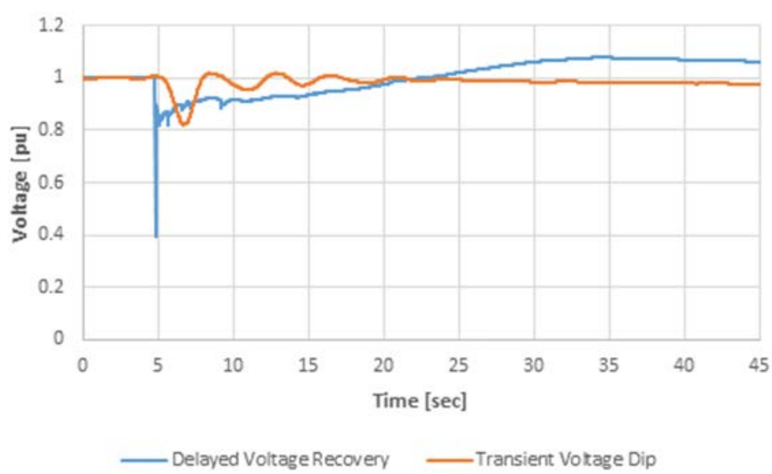

Figure 11: Transient Voltage Response – Voltage Dip vs. Delayed Voltage Recovery

[19] Static reactive devices should maintain pre-contingency voltages as much as possible to maximize dynamic reactive capability on the system. It is critical that dynamic reactive devices do not use all of their capability in the pre-contingency operating state.
[20] 2015 NERC-DOE Dynamic Load Modeling & Fault Induced Delayed Voltage Recovery (FIDVR) Workshop Materials, Available: HERE

Mid-Term Dynamics[21]

After the first swing transient voltage response, the system (if stable) will begin to dampen oscillations and return to a new steady-state condition. As the transient oscillations dampen out, the system is in a transitory state termed "mid-term dynamic." During this time frame, automated controls (e.g., fast switched shunt reactive devices) may be operating, dynamic resources are continually adjusting, and generator excitation systems are responding to maintain terminal voltage. This time frame may or may not consider automatic load tap changing based on the control delays associated with under-load tap changer (ULTC) action. Excitation limiters play an important role in this time frame and should be considered due to their time constants often outside the transient time frame. Slower manual controls are not included in the analysis (e.g., manual tap changing, operator-controlled capacitor switching, manually tripped interruptible load, etc.)

Long-Term Dynamics: Post-Contingency[22]

Once the system has dynamically found a new equilibrium point following a contingency, post-contingency analysis is performed to assess voltage stability and security. This analysis includes the results of all automatic control devices that respond within this defined time frame (e.g., 3 mins). These include excitation systems maintaining voltage schedule, power factor, etc., governor response, Automatic Generation Control (AGC), and other continuous control devices, including FACTS. Automatic tap changers[23] and automatic switched shunts are acting in this time frame to maintain voltage levels within control bands and are modeled appropriately in the analysis. Manual controls such as manual tap changing, manual capacitor switching, load shedding, etc., are not considered in this time frame – it is assumed that operators are not acting this quickly to major system events.

Steady-State: Post-Contingency[24]

The last time frame encompasses the applicable time associated with each entity's emergency ratings.[25] This means that the system returns to within acceptable operating limits within this time frame following an event and therefore the analysis time frame ends at this point. All manual readjustments and automatic controls are considered within this time frame. This includes generation re-dispatch, transformer tap changing, manual and automatic capacitor switching, fast- or slow-acting RAS, and any other form of system adjustment relevant to the contingency.

21 Typically 3 – 30 seconds.

22 Typically 30 seconds – 3 minutes.

23 Automatic tap changers between the boundary of the Transmission and Distribution systems should be considered in this time frame, where applicable. These automatic devices can have an impact on load response.

24 Typically 3 – 30 minutes.

25 For example, short- or long-term emergency ratings based on the entity's planning and operations practices.

Reactive Power Assessment Techniques

There are various types of planning techniques for studying reactive power control and requirements for reliable operation of the BPS. This section describes each type of planning technique and the situations where these analyses are useful.

Contingency Analysis

The BPS is planned and operated within its equipment normal thermal ratings and system voltage limits for conditions where all scheduled elements are in service (Normal condition). Contingency analysis is conducted to ensure that the system stays within its emergency thermal ratings and voltage limits immediately after a disturbance involving the loss of an element (single contingency or "N-1" condition), but without operator intervention. The system should be capable of such performance at all times,[26] including operations during minimum and maximum forecasted load conditions. This "N-1" condition applies to both steady state and stability requirements. In addition to satisfactory performance for normal system conditions and for single contingencies, the system should be able to withstand some selected "N-2" contingencies when determining stability limitations and also extreme (more severe but less probable) disturbances without suffering voltage collapse, cascading, or instability.

For voltage criteria testing, contingency analysis routinely checks for both voltage drop criteria and an absolute voltage criteria. The voltage drop is calculated as the decrease in bus voltage from the initial steady-state power flow to the post-contingency power flow. It ranges from two to six percent, depending on the adopted value by the region/utility. The absolute voltage criteria is examined for the same contingency set and it constitutes the acceptable lower and upper bus voltage magnitude limits immediately after a disturbance (e.g., 0.95 pu and 1.05 pu).

In general, contingencies that result in voltage collapse will not have a converged power flow solution in the post-contingency state. The diverged base case will generate results with erroneous conditions (extreme voltage, power flows, etc.) and does not provide credible results for analysis. However, the point at which the case diverges provides the stability limit; it does not provide the impact or propagation of this voltage collapse. An engineer will apply judgment and study the conditions leading up to the divergence to identify potential causes or mitigation measures for the collapse.

QV Analysis

QV analysis provides the sensitivity of bus voltage with respect to injections of reactive power at a given bus location. The purpose of QV analysis is to determine how much reactive margin a particular bus has before voltage collapse would occur under pre- and post-contingency operating conditions. A system is defined as voltage stable if the V-Q sensitivity[27] is positive for every bus and voltage unstable if V-Q sensitivity (reactive margin) is negative for any one bus. QV curves are generated by placing a dummy machine[28] at the bus being analyzed. The voltage set point of the dummy generator is varied over a range and its var output is adjusted to meet this scheduled set point. The vertical axis output of a QV curve shows the output of the generator Mvar and the horizontal axis shows the voltage set point (Figure 12). Positive Q represents reactive power output from the dummy generator while negative Q represents reactive power consumption. The base case operating point is represented by the intersection of the curve with the x-axis (zero reactive power output of the dummy generator) of the curve. As

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[26] It is allowable to have post-contingency mitigation plans where you may operate above emergency ratings and voltage limits with an operating plan to address that limit violation.

[27] A positive V-Q sensitivity refers to a positive change in reactive power generating a positive change in system voltage. This is inherently a stable condition (right side of the V-Q plot). On the other hand, a negative sensitivity results in a positive change in reactive power resulting in a reduction of voltage (unstable), which is the left side of the V-Q plot.

[28] A synchronous condenser to provide vars to control bus voltage under test.

voltage decreases from this point, reactive power is consumed by the fictitious machine. The minimum point ("bottom") of the curve represents the voltage stability point, which is the maximum allowable increase in load Mvar at the tested bus. The Q value at this minimum point is defined as the reactive power margin for this bus. That value should be below the x-axis (negative value, meaning consumption) for a stable operating condition; otherwise a minimum above the x-axis is an unstable operating condition.

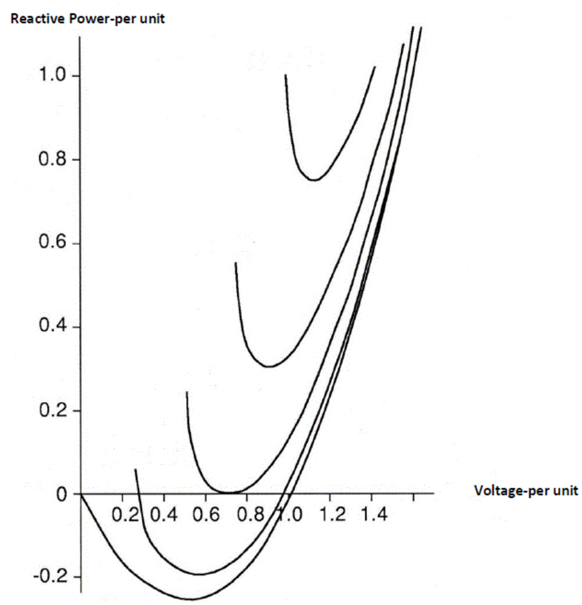

Figure 12: QV Curve[29] [Source: ©CIGRE, 1986]

QV analysis is performed for both pre-contingency and post-contingency operating conditions. For post-contingency simulations, the contingent line is removed from service to establish a new operating condition. Then QV curves are generated for that condition to establish the stability points for that contingency event. Prior to varying the voltage set point of the dummy generator, all static var devices are typically locked (switched shunts, LTCs, etc.). Dynamic reactive devices (i.e., devices expected to respond prior to voltage collapse) are allowed to respond as the set point voltage of the dummy generator is varied. When a nearby reactive device reaches its maximum or minimum output limit, there is a discontinuity in the QV curve.

A main advantage of QV analysis is that reactive power requirements can be computed without being affected by power flow convergence problems. At the same time, being a full AC power flow implementation, this method is capable of representing all system effects and controls without numerical compromise. However, the method has the drawback that a bus, representative of a particular voltage collapse condition, must be pre-selected and may not reveal wide-area voltage stability problems. Another drawback is evaluation speed; similar to PV analysis, QV analysis is relatively slow since it consists of running a series of power flow studies. However, parallel computing tools[30] can be used in these studies to eliminate speed concerns.

Although any positive margin is technically stable, utilities generally establish an "adequate margin" that is typically the size of a nearby capacitor group or other reactive device. For example, if a 500 kV bus has 320 Mvar of margin and that same bus also has a 300 Mvar capacitor, this is considered adequate margin because failure of the capacitor to switch would still provide margin to the collapse point. Another situation that can happen is if the Q_{min} point occurs at a very low voltage. For example, Q_{min} may occur at V = 0.70 pu; however, the grid is not

[29] CIGRÉ TF 38.01.03, "Planning Against Voltage Collapse," technical brochure No. 24, October 1986.

[30] "MPjobs – running PSS®E in parallel," PSS®E User Group Meeting, May 2015.

operated at that voltage magnitude. Instead, it may be useful to look at how much margin is available at higher voltages (i.e., V = 0.85 pu) and use that as the reactive margin even if it is not the Q_{min} point. This provides an assessment of the margin of failure before serious problems occur at other operating voltages.[31] However, determining which bus in an area has the least reactive margin for a given contingency is also a challenge; often many buses will be screened for each contingency. Contingencies with negative margin are often initially identified in standard power flow contingency analysis as contingency solutions that diverge.

PV Analysis

PV analysis is a key tool in computing transfer capability and operating limits for interfaces and transmission paths that are known to be limited by voltage stability. It provides the sensitivity of bus voltages with respect to increasing transfers of active power (MW) between a source and sink. PV analysis is the primary technique that provides the proximity to voltage collapse in terms of active power transfer. The analysis can be performed for pre- or post-contingency conditions. This is a commonly used tool to understand operating limits with respect to voltage performance on the BPS.

PV analysis involves increasing real power transfers from an initial operating state and monitoring the voltage performance of the grid in either pre- or post-contingency conditions. Active power transfer is increased using a combination of generation and load changes in the source and sink areas. Generally, generation is ramped up in the source area and load is increased in the sink area (G-L transfer); however, other transfers strategies include: 1) increasing generation in the source area while decreasing generation in the sink area (G-G transfer) or 2) decreasing load in the source area while increasing load in the sink area (L-L transfer). For a post-contingency analysis, a contingency is applied following each step increase in the transfer. As described in the previous section, in the pre-contingency time frame, all controls are modeled. Whereas in the post-contingency (3-30 minute) time frame, only automatic controls are modeled. As with all steady-state analysis, interactions between the controls and the operation of undervoltage load shedding, under frequency load shedding, and remedial action schemes cannot be properly studied.

The point of voltage instability can be determined using PV analysis and provides information related to the amount of allowable power transfer as well as the locations where reactive power may be deficient to support voltage. The maximum power transfer point ("nose" or "knee" of the curve) is the point where an incremental transfer will result in an inverse, unstable relationship between voltage and power (voltage instability). Near the nose of the curve, the magnitude of the voltage sensitivity, dV/dP increases rapidly. A power flow solution will generally be non-convergent at or beyond the nose of the curve. For convergent power flows, the transfer may also be limited by thermal limits, reactive reserve margin limits, voltage violations such as pre- or post-contingency steady-state voltage limits, or voltage deviation limits. The voltage stability limit is the maximum power transfer point. To determine the Total Transfer Capability (TTC) a margin is used to account for possible inaccuracies in the modeling. The margin may be a constant MW value, but generally it is calculated as a percentage of the maximum power transfer using a voltage security factor. Typically[32], voltage security factors are 5% for single contingencies and 2.5% for double contingencies. Extensive studies are necessary to assign an appropriate margin. These same studies may show that a single margin does not work well system-wide. Figure 13 illustrates the functions of a PV curve for determining system limits.

[31] Remember to scale reactive margin from QV analysis at minimum voltage accordingly for determining nominal voltage capacity required (e.g., the voltage squared relationship for shunt capacitors).

[32] These voltage security factors are based on engineering judgment, operating experience, and extensive testing.

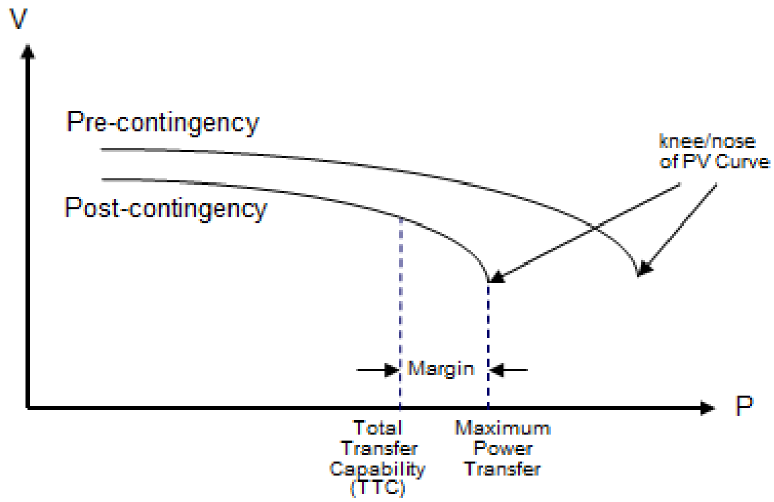

Figure 13: PV Curve Examples

Transient Stability Analysis

Following the clearing of a fault, voltage will swing back up and then swing down. On the swing back down following the clearing of a fault, avoiding excessively large transient voltage dips is important both from a power quality perspective and from a BPS reliability perspective. The swing should not be so large as to cause additional facilities to trip (load or generation). Also, the dip should not be so large as to cause a voltage collapse. Many factors influence how large the transient dip is, including pre-contingency MW transfer levels, MW load levels, pre-contingency voltage levels, and pre-contingency dynamic reactive reserve levels. A smaller MW transfer amount, a higher pre-contingency voltage, and a larger amount of well-situated local dynamic reactive reserve will result in a smaller transient voltage dip following a disturbance. If a simulation shows that a transient voltage dip is unacceptably large, the dip can be reduced by either reducing MW transfer levels, increasing pre-contingency voltages by bringing on more static reactive devices or dynamic reactive devices, or increasing dynamic reactive reserve by bringing on more well-situated local static reactive devices (thereby reducing output of dynamic reactive devices in pre-contingency).

Reactive Power Sufficiency

Reactive power planning and reactive needs in the operating horizon vary significantly between TOPs across the NERC footprint. In the operating horizon, sufficient reactive resources need to be available to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection. In the planning horizon, sufficient reactive resources need to be planned for, such that the transmission system can meet planning performance requirements and result in a system that can be operated reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

Reactive Reserve

Having an appropriate amount of reactive reserve in pre-contingency is important to ensure that a transient or post-transient voltage collapse does not occur following a disturbance. Because a voltage collapse may be fast, typically only dynamic reactive reserve is counted as reactive reserve. Typically a system that is more stressed in a pre-contingency state will have larger pre-contingency reactive reserve requirements in order to maintain stability following a contingency. System stress increases as MW transfers across the system increase. For example, a system with a small pre-contingency MW transfer level may have a small reactive reserve requirement; as that MW transfer level increases, the reactive reserve requirement will also increase. In order to meet the increased reactive reserve requirement, an operator may switch in capacitors in the pre-contingency state to reduce the var output of dynamic device or the operator may bring more dynamic devices (i.e., more generators) online.

The dynamic reactive reserve of a device is measured as the difference between its present var output and its maximum var output. Its maximum var output is usually defined as that which can be sustained for an extended period (i.e., 30 minutes or longer). For example, the one to two minute overload capability of a STATCOM is not included as dynamic reactive reserve. For a generator, the maximum var limit is its steady state limit – the capability from the generator "D" curve or the most limiting factor that prohibits reaching the generator capability[33] (e.g., excitation limiter) – not its transient maximum var output prior to over excitation limiter action.

Generally, the operator will maintain a margin to ensure that transfers are lower than the maximum power transfer point and that stability is maintained. Defining reactive reserve requirements as the margin[34] on a PV curve is often used because it reflects prevailing system conditions, specifically transmission outages and active and reactive power dispatch.

Deriving Voltage Schedules

Often, TOPs develop system voltage schedules based on nominal voltage level and system-specific requirements. The system voltage schedule is part of the TOP's operating plan to maintain equipment within safe and reliable voltage levels and within operating limits. Reactive resources are operated to stay within applicable facility ratings to protect equipment from abnormal voltage levels. TOPs will develop schedules based on local needs as well as wide-area considerations (e.g., adjacent TOP voltage scheduling practices, minimizing reactive losses, and maximizing transfer capability).

Generators are required to provide voltage or reactive power control to maintain system voltage levels for the reliable transfer of active power to serve load. Resources interconnected with the BES are issued a voltage schedule or reactive power schedule to be maintained at the POI between the generator and transmission system. The schedule is provided to the GOP as either a set point voltage level, range of acceptable operating voltages (set

[33] These reactive capability limits of the unit are established as part of MOD-025-2 testing.

[34] While a PV curve does not explicitly include reactive power, a reactive power margin (difference between actual and maximum capacity) may be used as an underlying limit in the simulations to set the operating limits.

point with range), or power factor control set point. Generally, a voltage range or target value and a tolerance band are provided to the GOP (determined by the TOP) for normal operating conditions:

- **Range:** a range of acceptable operating voltages (e.g., 1.02-1.04 pu)
- **Target Set Point**: the preferred voltage or power factor under normal operating conditions
  - **Target Voltage**: typically slightly above nominal voltage level (e.g., 1.02-1.05 pu)
  - **Target Power Factor**: typically around unity (1.0) power factor
- **Tolerance Band**: minimum and maximum voltage or power factor range under normal operating conditions
  - **Voltage Tolerance**: typically a small bandwidth around the target set point (e.g., 1-2%)[35]
  - **Power Factor Tolerance**: typically a small bandwidth around the target power factor (e.g., ± 0.01)

The TOP can modify the voltage range or target set point and tolerance band based on impending system conditions considering capabilities of the generating facility, including ad hoc modifications to the voltage or reactive power schedules based on unplanned or unexpected operating conditions. While the voltage or power factor set point and tolerance band or range accounts for normal operating conditions, there generally is a wider range of acceptable maximum and minimum SOLs. Often, the scheduled operating voltage are defined in a manual or table used by the TOP, and voltage set point values may change based on peak and off-peak system conditions based on expected operating voltages. Table 1 shows an illustration of typical operating voltage schedules used by a system operator.

[35] For example, in PJM the Transmission Owners must supply and communicate in writing voltage schedules and a low and high bandwidth or the PJM default voltage schedules from PJM Manual 3 "Transmission Operations" as listed below apply:

Nominal Voltage (kV):	[765	500	345	230	161	138	115	69	66]
Voltage Schedule (kV):	[760	525	350	235	164	139.5	117	70	67]
Bandwidth (± kV):	[10	8	7	4	4	3.5	3	2	1.5]

Table 1: Typical Operating Voltage Schedule Tables									
Bus #	Nominal Voltage [kV]	Typical Operational Voltage Schedules - On-Peak Period			Typical Operational Voltage Schedules - Off-Peak Period			Typical Acceptable Max/Min Voltage Schedule Range	
		kV Sched	Tolerance Band		kV Sched	Tolerance Band		Max kV	Min kV
			kV High	kV Low		kV High	kV Low		
1	345	356	359	353	356	359	353	362	327
2	115	116	118	114	116	118	114	121	109
3	115	118	120	116	117	119	115	121	110
4	115	119	121	117	117	119	115	121	110
5	345	358	361	355	356	359	353	362	335
6	115	118	120	116	118	120	116	121	109

Generator target voltages should be set to support secure operation of the BES for pre- and post-contingency conditions. Determining these schedules is based on operating experience and coordinated with voltages of neighboring TOPs and other reactive power devices. Generator voltage and reactive power schedules are determined by the TOP and are typically based on:

- BPS reliability and security
- Internal generator operating constraints limiting plant capabilities including auxiliary bus voltage and plant-level loads
- Iterative communication process between the TOP and GOP
- IEEE Standard C57.116:[36] transformers directly connected to generators and the concept that generators can deliver a broad range of reactive power to the low voltage side of the GSU to keep system voltage near target voltage and within the tolerance band.
- IEEE Standard C50.13:[37] states that "Generator shall be thermally capable of continuous operation within the confines of their reactive capability curves over the ranges of ±5% in voltage and ±2% in frequency…"

This voltage range or tolerance band does not preclude temporary voltage or power factor excursions beyond the specified limits set by the TOP, particularly due to abnormal system conditions. Excursions outside of a specified schedule are unavoidable due to contingency events; however, these temporary excursions are generally limited in extent, frequency, and duration. When they do occur, corrective actions should be taken to return system voltage to within acceptable system voltage limits as soon as possible. TOPs, working with the RC, should make determinations of the timing and actions to be taken to return values to within the specified voltage schedule. In addition, automatic controls (particularly dynamic reactive resources) should also support post-contingency voltage by quickly responding to abnormal voltage conditions.

[36] *IEEE Guide for Transformer Directly Connected to Generators*, IEEE Standard C57.116-2014, 2014.
[37] *IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above*, IEEE Standard C50.13-2014, 2014.

Generator Voltage Control

Generators are the largest and most prevalent Reactive Power resource and play an integral role in maintaining voltage stability of the BPS. The dynamic reactive capability available on most generators contributes to the robustness of reactive resources available to respond to a wide array of postulated contingencies.

The TOPs provide a voltage schedule (which is either a range or a target value with an associated tolerance band) for generators at either the high side or low side of the GSU transformer. In addition, to ensure that the generator provides dynamic reactive support to the system, the GOP should ensure that the generator operates with its AVR in service at all times unless exempted by its TOP or unless the AVR is temporarily unavailable for maintenance or repairs. Notifications from the GOP to its TOP are required anytime the AVR is out of service.

The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP's Facility during normal operations and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule bandwidth should not be confused with the control dead-band that is programmed into a GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule bandwidth.

Units are often equipped with AVRs that can automatically compensate for calculated voltage drops from the control point to an external point on the system (e.g., the high side of the GSU). In these occurrences, the AVR signal is automatically adjusted to account for the voltage drop across the external equipment.[38] In instances where several units are tied to the same bus, there are often automatic schemes to adjust the units such that all the units contribute a share of the total plant reactive output. Such schemes include using a generator AVR's line-drop compensation capability to regulate to a point electrically separate from the other local generators, such as a point inside the generator GSU.

For instances where the AVR cannot, or the entity chooses not to, use automatic voltage drop compensation, the GOP that does not monitor voltage at the location specified by the TOP should convert the schedule to the voltage point monitored by the GOP. There are many ways to convert the voltage schedule, including the development of voltage regulation curves to account for transformer losses or the use of straight ratio conversion.

Under certain circumstances, the TOP can specify an alternative method of control to a GOP such as a Reactive Power Schedule. Whichever the method of control; the GOP needs to convert the schedule to a control point monitored by the GOP.

Some more advanced controls may include an AVR for transient response and a slower outer loop controlling to a power factor set point in steady-state. This may be useful when the TOP supplies a power factor schedule but needs transient response from the generator.

Generator Automatic Voltage Control Techniques

AVRs in generator excitation systems fundamentally use the generator terminal voltage as a feedback signal for control. However, in some situations, compensation may be used to control a location that is not the generator terminal voltage. Techniques include:

- **Line Drop Compensation (LDC):** compensation technique used to achieve better high-side system voltage control, particularly for situations where impedance of the GSU is large
- **Reactive Current Compensation (RCC):** a technique required for stable sharing of reactive power among parallel generators whose terminals are connected at the same bus (and likely sharing a common GSU)

[38] GSU voltage drop compensation should be studied carefully to ensure stable operation and avoid excessive compensation (e.g., >60% of transformer impedance). An alternative approach may include pulsing the AVR generator voltage set point using a high-side voltage signal from the TO and a PID control loop in the DCS.

- **Cross Current Compensation (CCC):** a technique used only in unique circumstances for stable sharing of reactive power among parallel generators connected at the same bus who have LDC deployed on each unit.

LDC is accomplished by adding a term proportional to generator reactive power/current to the reference voltage; the term is generally set to one-fourth to one-half of the generator step up transformer impedance. LDC is usually implemented on a single unit connected through a dedicated GSU. The result is increased generator response to deviations in system voltage at the POI due to the additive compensation term.

RCC is accomplished by subtracting a term proportional to generator reactive power/current from the reference voltage and is always implemented for parallel units connected to the same bus. RCC limits generator response to disturbances and voltage deviations because the AVR controls voltage at a fictitious point inside the generator terminals. An impedance is effectively inserted between the machines, making the control less sensitive to the network voltage deviations at the POI. This ensures stable reactive power sharing across units.

Neglecting transformer resistance and assuming near-unity generator voltages, the POI voltage (per unit basis) can be approximated in different operating modes as:

$$V_{POI} = V_G - X_T * Q \qquad \text{Terminal Voltage Control}$$
$$V_{POI} = V_G + Q * (X_{COMP} - X_T) \qquad \text{Line Drop Compensation}$$
$$V_{POI} = V_G - Q * (X_{COMP} + X_T) \qquad \text{Reactive Current Compensation}$$

where V_G is the generator terminal voltage, V_{POI} is the voltage at the POI, X_T is the transformer reactance, Q is the generator reactive power output. For LDC and RCC, this simply modifies the AVR reference voltage by

$$V_{COMP} = V_{ref} + X_C * Q$$

where V_{COMP} is the compensated voltage, V_{ref} is the voltage reference voltage, and X_C is the compensating factor (e.g., 5%).

CCC is used in rare situations where multiple units connected to the same bus require LDC. In this case, CCC is used to effectively apply RCC to the units to ensure stable sharing of reactive power and also provide LDC to support system voltage. The equation for CCC, neglecting transformer and compensation resistance, is shown below, which includes a component of RCC and LDC.

$$V_{COMP,A} = V_{GEN} - X_C * (Q_A - Q_B) - X_{COMP,A} * Q_A \qquad \text{Unit A CCC}$$
$$V_{COMP,B} = V_{GEN} + X_C * (Q_A - Q_B) - X_{COMP,B} * Q_B \qquad \text{Unit B CCC}$$

where X_C is the cross-compensation reactance, and $X_{COMP,A}$ and $X_{COMP,B}$ are the series compensation reactances (from the powerflow data) of Units A and B.

Figure 14 illustrates a single unit with dedicated GSU in either terminal voltage control, LDC, or CCC mode; Figure 15 illustrates two parallel generators requiring CCC; Figure 16 illustrates two parallel generators requiring CCC with LDC added to compensate for POI voltage control.

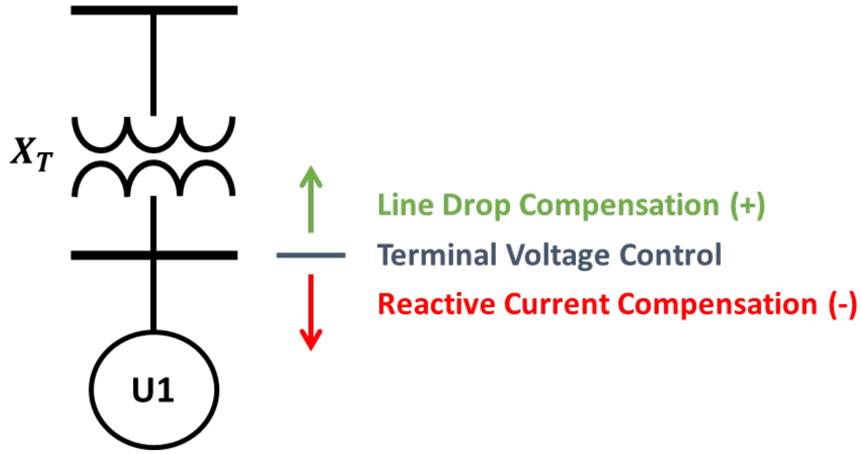

Figure 14: Single Unit Compensation Mechanisms

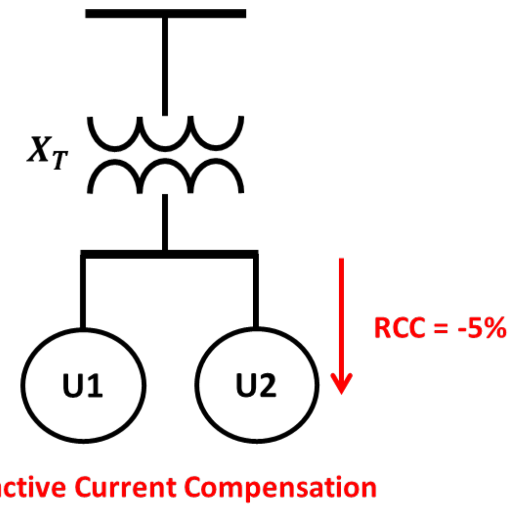

Figure 15: Parallel Unit Reactive Current Compensation

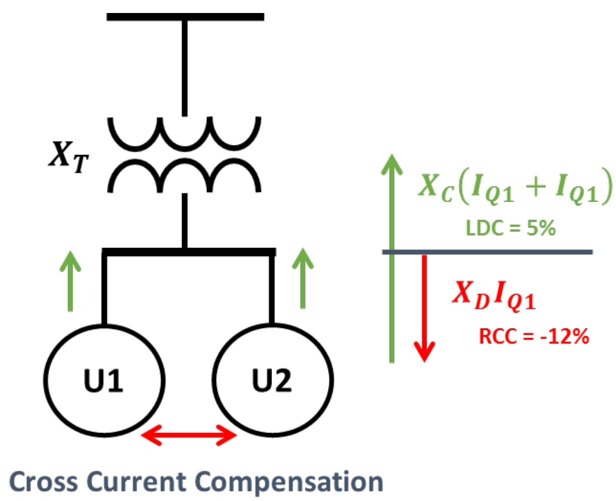

Figure 16: Cross Current Compensation

Generator Automatic Voltage Control and Plant-Level Controls

The AVR of a generating unit should operate in automatic voltage control mode with its automatic voltage regulator (AVR) in service and controlling voltage. The AVR generally uses terminal voltage, or compensated voltage, as feedback for this control. The control logic should not have any intentional time delays[39] or deadband imposed other than what is attributed to the physical characteristics of the machine and control logic. Similarly, no intentional droop characteristic should be added to the AVR other than the natural reactive-voltage droop as seen at the POI. This is based on the impedance between the generator terminals and the POI.[40] Figure 17 shows inherent droop characteristics for terminal voltage control, LDC, and Reactive Current Compensation.

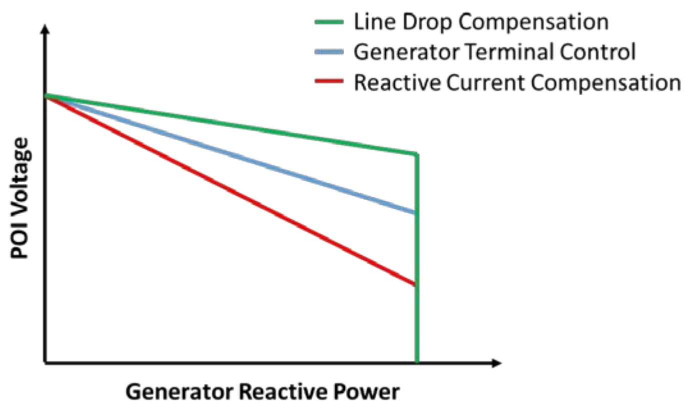

Figure 17: Voltage Control Effects on Droop Characteristic

As the figure clearly illustrates, LDC is used to ensure that sufficient reactive power is delivered to the system for a given drop in system voltage. This is coordinated with the reactive capability of the machine as well as the voltage support needs of the BPS and expected scheduled voltage range.

Outer loop, SCADA-based, or plant-level controls such as a Distributed Control System (DCS) should not interfere with the automatic regulation of voltage to a scheduled set point. Automatic control of voltage ensures the system has sufficient reactive power to meet reasonable voltages pre- and post-contingency. The AVR acts quickly on the excitation of the machine to provide or consume reactive current in an effort to support voltage (dynamic reactive capability). Plant-level controls that act on the AVR can retract this voltage support following a disturbance at the point where this support is most needed maintain acceptable voltage levels. In the transient time frame, this is critical for transient voltage stability; however, this is also critical in for longer time frames as this can affect longer-term voltage stability. For example, following a system event resulting in low terminal voltage, the AVR will increase the field current and supply reactive power to the system to maintain terminal voltage output (and respective POI voltage as per the impedance-droop). Any outer loop controls that act on the reactive power output or set point essentially result in the unit not being operated in automatic voltage control mode and should be avoided.[41]

Dynamic and Static Reactive Resources

Along with the magnitude of the reactive resource, one of the critical factors in scheduling or planning "sufficient reactive resources" is the operational characteristics of the resource. Static reactive resources provide a fixed nominal contribution when in-service while dynamic reactive resources provide controllable reactive power output in real-time to maintain a set point power output or voltage. The amount of "sufficient" resources depends on the type of resource available. A balance between dynamic and static resources should be robust enough to

[39] This predominantly applies to synchronous machines, not necessarily renewable energy resources.

[40] Any unique cases should be coordinated between the GO, GOP, TOP, and RC.

[41] In cases where these controls are acting on the AVR, a corrective action plan should be coordinated between the GO, GOP, TOP, and RC.

support acceptable steady-state voltage limits, post-contingency voltage deviations, and transient voltage response when subjected to an array of potential contingencies.

Static reactive resources are committed pre-contingency and may or may not be allowed to switch[42] post-contingency in the planning studies. An overreliance on static resources can result in acceptable or even high voltages pre-contingency but unacceptable post-contingency voltages. Figure 18 illustrates the fundamental change in PV characteristic for increasing dependence on static resources. Due to the static nature of the resource, operational constraints may develop due to minimal automatic control of voltage or reactive power output. Developing an acceptable mix of static and dynamic reactive resources is highly dependent on local system characteristics and practices. As the ratio of static to dynamic reactive resources increases, the pre- and post-contingency voltages remain flatter, but the "nose" of the PV curve becomes substantially steeper. Voltage magnitude becomes less indicative of system collapse and reactive margins become harder to determine. It is noted that dynamic reactive devices can also create a flatter voltage profile when operating in voltage control mode. However, while their innate ability to provide more vars when needed supports reliability, these resources hitting their maximum capabilities can create discontinuities in the PV curve and should be analyzed accordingly.

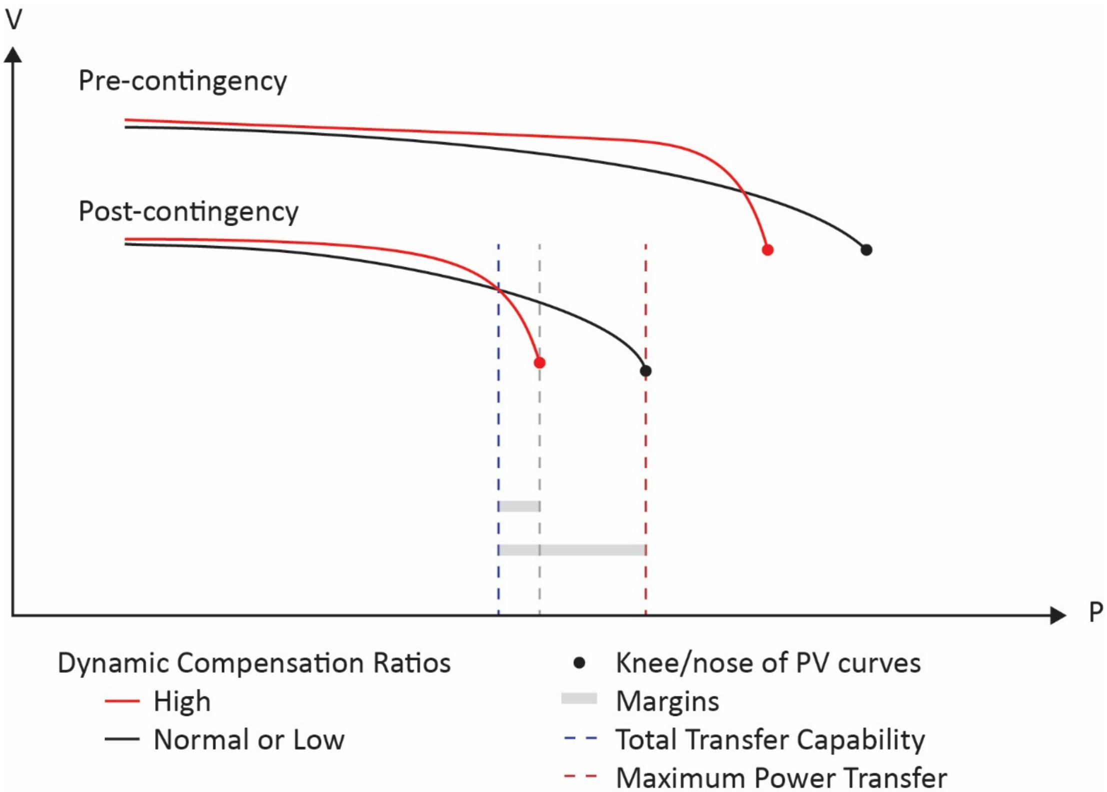

Figure 18: PV Curve Results for High Ratio of Static/Dynamic Reactive Compensation

[42] This is not a common practice across the interconnections and should be considered particularly for studies between PC planning areas.

Operational Time-Dependent Voltage Limits

Drawing a parallel with the use of time-dependent thermal limits (normal, LTE, STE), TOPs may opt to consider time-dependent high and low voltage limits. The TOP should work closely with related GOPs in developing these time-dependent voltage limits and also ensure an effective communications process for exceedances of these limits. There is an acknowledgment that short duration exposure to potential high or low post-contingency voltages represents an acceptable risk knowing operator action within that short period of time can eliminate the exceedance. There may be exceptions to these limits for specific units or operating regions that both the TOP and GOP would need to be aware of. The limits should be coordinated with voltage equipment design parameters and ratings, load and generation tripping levels, and other applicable limits that could impact reliability at these higher or lower voltages (e.g., UVLS) in the short time prior to mitigation. An example of time-dependent voltage limits is provided in Figure 19 and Table 2.

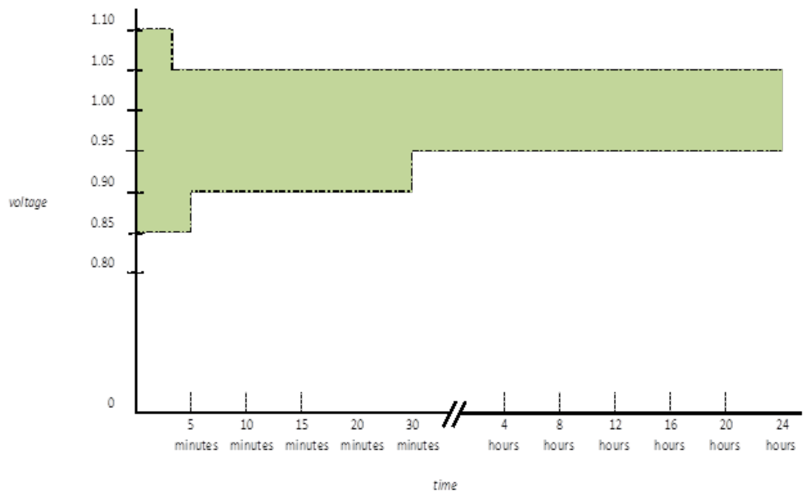

Figure 19: Time-Dependent Voltage Limit Illustration

Table 2: Time Dependent Voltage Limit Example

Normal Voltage Limits (NORMVL)

TO	115 kV		345 kV	
	Low Voltage Limits (kV)	High Voltage Limits (kV)	Low Voltage Limits (kV)	High Voltage Limits (kV)
TO 1	109.0	121.0	328.0	362.0
TO 2	109.3	122.0	327.8	362.0
TO 3	109.3	121.0	327.8	362.0

Long Time Emergency Voltage Limits (LTEVL)

	115 kV			345 kV		
TO	Time Applicable	Low Voltage Limits (kV)	High Voltage Limits (kV)	Time Applicable	Low Voltage Limits (kV)	High Voltage Limits (kV)
TO 1	Infinite	105.0	121.0	N.A.	N.A.	N.A.
TO 2	30 minutes	105.8	124.0	N.A.	N.A.	N.A.
TO 3	Load cycle	103.5	121.0	Load cycle	310.5	362.0

Short Time Emergency Voltage Limits (STEVL 15 Minutes only)

TO	115 kV		345 kV	
	Low Voltage Limits (kV)	High Voltage Limits (kV)	Low Voltage Limits (kV)	High voltage limits (kV)
TO 1	102.0	121.0	N.A.	N.A.
TO 2	N.A.	N.A.	327.8	369.0
TO 3	100.0	121.0	N.A.	N.A.

Drastic Action Voltage Limits (DAVL 5 Minutes only)

TO	115 kV		345 kV	
	Low Voltage Limits (kV)	High Voltage Limits (kV)	Low Voltage Limits (kV)	High Voltage Limits (kV)
TO 1	100.0	121.0	N.A.	N.A.
TO 2	N.A.	N.A.	N.A.	N.A.
TO 3	98.0	121.0	N.A.	N.A.

Voltage Response

Voltage response refers to the system's response in voltage following a grid disturbance. The starting voltage, transient voltage response, and duration of the response are a measure of the system strength. A voltage drop and recovery that results from a system short circuit or fault depends on the location of the fault in relation to the measured voltage. It may vary from zero to a few percent of normal. The duration of the voltage response is determined by the fault clearing time and ranges from as low as three cycles on 345 kV systems to one or more seconds on 34.5 kV sub-transmission systems. Following the fault clearing, the voltage passes through a transient recovery period before settling to the post-fault value. During this oscillatory transient period, additional voltage dips typically occur immediately after the voltage attempts to return to the pre-fault level due to machine acceleration during the fault, resulting power swings, excitation system behavior, and motor reacceleration.

During the fault period, active power transferred from the generators to the system is reduced, causing the generators' internal angles to advance. When the fault is cleared, the generators have to supply the pre-fault active power again, and their internal angle moves toward their pre-fault value. This oscillatory behavior of local generators, coupled with motors' demand for accelerating power (the motors have slowed down during the lower fault voltage and will reaccelerate), may cause a new short-term voltage dip on the system. This second dip in voltage is then followed by an oscillatory transition to the post-fault steady-state voltage as the machine prime mover power is again in balance with the electric load.

Voltage disturbances caused by high voltage transmission faults are classified as "instantaneous sags" in IEEE Standard 1159-2009[43] Table 2 (0.5 cycles to 30 cycles, 0.1 to 0.9 pu voltage), and the post-fault voltage dips are categorized as "momentary" (30 cycles to 3 seconds, 0.1 to 0.9 pu voltage). Instantaneous sags affect customers depending on the sensitivity of their equipment and the extent of their power conditioning. IEEE Standard 493-2007[44] ("Gold Book") reports that voltages to 85-90% of nominal for a duration as short as one electrical cycle have triggered immediate outages of critical industrial processes. In the same standard, Table 9-12 accounts for sags ranging from 90–70% with durations up to 1250 milliseconds to include the effect of motor starting. Voltage dips tend to affect sensitive loads (e.g., computer, computer-based equipment, power conversion, etc.) Domestic and commercial electronic (computer) loads are more likely to ride through a sag if the magnitude and duration are within the ITIC[45] curve. Single-phase air conditioners may stall, consuming up to seven times rated reactive power due to locked rotor conditions. These compressor motors will remain stalled until their thermal protection trips them offline.[46] Industrial loads are the most vulnerable to severe voltage disturbances.[47] If a motor or energy management system (EMS) control contactor is unable to ride through a voltage sag, the motor and associated process is interrupted.

WECC transient voltage dip criteria is based, in part, on a need to maintain a margin for nuclear unit auxiliary undervoltage protection and load transfer. A more general application is found in the setting guidelines of load-transfer devices in IEEE Standard 446-1995(R2000).[48] In Section 4.3.6 of this Standard, typical transfer threshold settings of 75% to 95% of pickup are given, with pickup settings ranging from 85–98% of nominal. Time delays are on the order of one second. This means that voltages below 80% (the limit suggested on the ITIC curve) are likely to initiate automatic load transfers.

Voltage sags in power systems are unavoidable; however, the system can be designed and operated to minimize severe voltage sags. High-speed fault clearing, special protection systems, field forcing, transmission reinforcements, and transmission interface transfer limits can be considered by GOs and TOs as options to improve voltage sag performance. Customers can apply power-conditioning technologies such as Uninterruptible Power Supplies (UPS) to sensitive loads.

Light Load Operating Conditions

The system is designed and operated to meet system performance criteria for conditions ranging from the peak period of a heavy load day through an extremely light-load period (e.g., early morning hours during a spring or fall holiday weekend). To ensure there is necessary operational flexibility, TPs and TOPs should consider a sufficient mix of lagging and leading reactive power resources for controlling system voltages over the full range of possible load levels.

Normal and emergency high voltage limits should not be exceeded in real-time on both a pre- and post-contingency basis, respectively. While high-voltage conditions are not as likely to propagate across the interconnection as extremely low-voltage conditions, they can result in significant equipment damage.

[43] *IEEE Recommended Practice for Monitoring Electric Power Quality*, IEEE Standard 1159-2009, 2009.

[44] *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems*, IEEE Standard 493-2007, 2007.

[45] ITIC: Information Technology Industrial Council

[46] *Technical Reference Paper: Fault Induced Delayed Voltage Recovery*, Princeton, NJ: North American Electric Reliability Corporation, 2009.

[47] *IEEE Recommended Practice for Electric Power Distribution for Industrial Plants*, IEEE Standard 141-1993.

[48] *IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications*, IEEE Standard 446-1995(R2000), 2001.

Additionally, high-voltage conditions, either in the steady-state or transient time frames, can lead to tripping of generation (especially inverter-based generation such as intermittent renewable resources) or load. Planning studies should pay careful attention to transient high voltages when interconnecting these resources to ensure both that the new resources can ride through expected high-voltage events and also that they do not worsen high-voltage conditions for other nearby units.

Operations personnel use real-time reliability monitoring and analysis capabilities to evaluate the actual pre- and post-contingency state of the system and a forward looking forecasted state of the system. If actual or simulated post-contingency conditions indicate high voltage limits may be exceeded, the operator will take action to reduce the voltage. Typical techniques to control high voltages include:

- Switching shunt capacitors out-of-service
- Switching shunt reactors in-service
- Operating synchronous generators/condensers in leading power factor (var absorbing) mode by changing generator voltage set points
- Adjusting the voltage set point of dynamic reactive resources (SVC, STATCOM)
- Changing transformer tap positions
- Changing phase angle regulating transformer (PAR) settings to adjust real-power flows,
- Switching transmission facilities in/out of service
- Bringing additional generating resources online (reactive capability)

Reactive Power Coordination

Reactive power and voltage control should be coordinated across operating entities. Key points for coordination between the generation, transmission, and distribution system, as well as between entities on these systems is described in this section.

Transmission to Distribution Coordination

Modeling

The boundary between TO and DP in power flow, stability analysis, and real-time is usually defined by explicit loads modeled as MW and Mvar. These loads may simply be modeled on the high side of the bus/substation or potentially modeled behind the step-down transformers and/or equivalent distribution impedances. The voltage and reactive power performance of the BES can be impacted by the load power factor (LPF) modeled across the TO-DP boundary. Loads should not over-rely on reactive support (lagging or leading) from the BES. Conversely, the BES should not solely depend on the load for reactive support (lagging or leading). Coordination between the TO and DP is important in determining what the proposed LPF should be at critical load levels (e.g., peak and light load).

Planning

To conduct necessary future studies, TPs use a forecasted active power demand and a representative load power factor (LPF). Joint studies between TO and DP may be required to determine a set of mutually agreed upon minimum and maximum LPF to assure that the system is planned and operated in an efficient and reliable manner. The determination of an optimal LPF will inherently result in the appropriate level of reactive support installed on both the distribution and BES systems. Having a minimum and maximum LPF will also ensure the reactive component of the load will not contribute to low or high voltages on the BES. If power factor falls outside this bandwidth, the DP should take action in their reactive power plan to correct their LPF to meet or exceed this agreed-upon bandwidth. The LPF at the TO/DP boundary does not need to be unity power factor; however, a reasonable and acceptable range is recommended. Definition of the LPF should clearly differentiate and consider all applicable reactive compensation at both the DP- and TO-side of the boundary point as well as all relevant contingencies.

For example, PJM requirements for the minimum power factor at the transmission/distribution interface are specified in PJM Manual 14B Attachment D "PJM Region Transmission Planning Process." The Regional Transmission Expansion Planning (RTEP) base case, which includes a 5-year horizon system representation and nondiversified forecasted 50/50 summer peak load, will be used for this analysis. System load will be represented at an area- or zone-wide minimum power factor of 0.97 lagging, as measured at the transmission-distribution interface point.

ISO-NE, as another example, also defines load power factor practices in planning and operations. *ISO-NE Transmission Planning Technical Guide*, Section 6, describes the load power factor assumptions used in system studies. It states that "each transmission owner in New England uses a process that is specific and appropriate to their particular service area to determine the load power factor to be assumed for loads in its service territory." The different methods are documented in the guide for the 90/10 Peak-Load case as well as assumptions for Intermediate-Load and Light-Load cases. As a default, ISO-NE uses a power factor at Minimum Load set to 0.998 leading at the distribution bus for all scaling, with some exceptions documented. Furthermore, ISO-NE operations uses specific requirements defined in *ISO-NE Operating Procedure 17, Load Power Factor Correction* for determined sub-areas within New England. Figure 20 shows an example of LPF curve for a given study area that ISO-NE uses operationally to ensure the distribution system loads are within a suitable and reasonable power factor range.

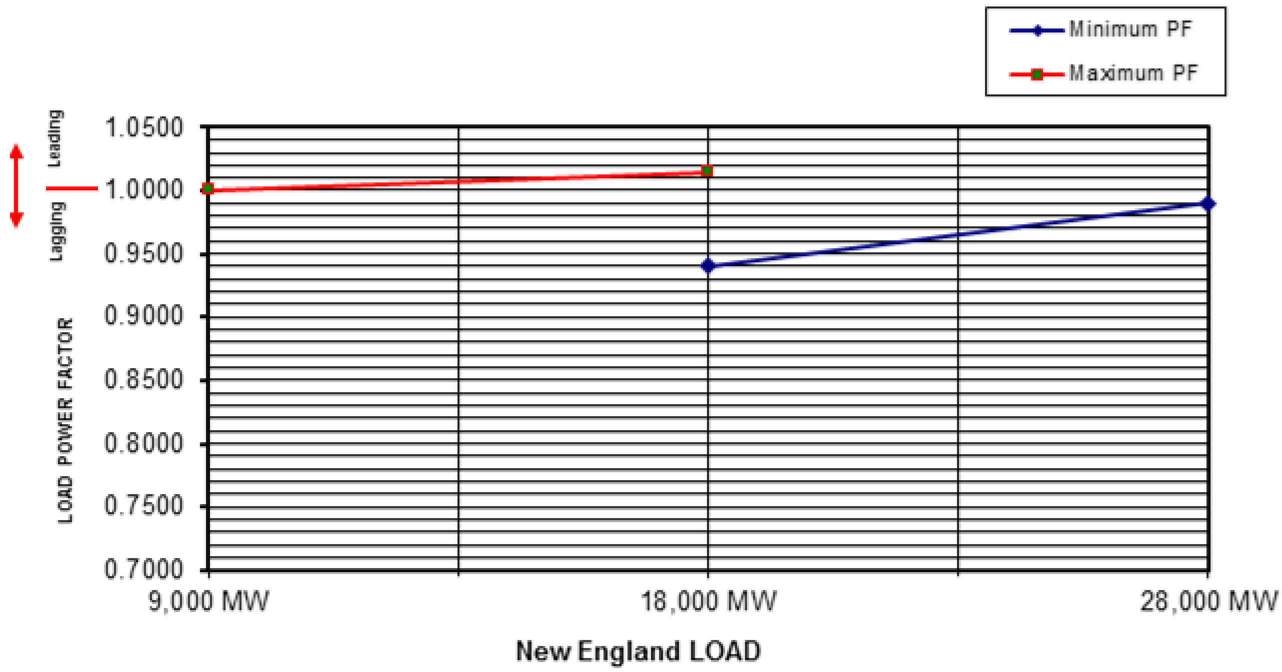

Figure 20: Example of Load Power Factor Curve for a Given Study Area [Source: ISO-NE]

Operations

MW and Mvar loads are actively displayed to system operators in the EMS via SCADA. In the event of real-time voltage events or predicated post-contingency voltage events as seen in the real-time contingency analysis (RTCA), the TOP may opt to further coordinate with the DP in real-time to potentially adjust distribution compensation to alter the LPF to provide additional support to the BES. This is generally in the form of switching distribution side reactive devices to alter the net LPF as seen by the BES.

Recommended Practices

Forecasted LPF should be reviewed periodically using real-time measured MW and Mvar values at the load aggregation points for operating conditions modeled in the case (e.g., heavy summer peak, off-peak shoulder, heavy winter peak, etc.) Depending on SCADA availability at the metering locations relative to actual load location, an agreed upon methodology should be established to accurately measure and report the LPF at the TO-DP boundary. LPF's outside the defined bandwidth should be reconciled on a periodic basis by the TO and DP.

NERC Reliability Standards do not require any specific LPF or specify any minimum LPF requirements at the TO-DP boundary. This is left up to the TO to specify in their tariffs, other mandatory operating procedures, or documented coordination agreements with the DP.

Transmission to Generation Coordination

As discussed above, FERC has established the reactive power capabilities at the POI for synchronous generation and recently issued Order No. 827 eliminating the exemption for non-synchronous generators to require reactive power capabilities at the high-side of the generator substation. Newly interconnecting non-synchronous generation is defined in Order No. 827. Existing generators are expected to provide the reactive power capabilities in accordance with the most recently signed interconnection service agreement. The TO should periodically review with the GO the expected reactive power performance for each generator. MOD-025 requires that generator active and reactive power capability be verified and reported to the TP for accurate system studies.[49, 50] The TO should also require the GO to provide information on future changes to any generator that would change the reactive power capabilities of the generator. The TO should assure that the assessments of near term and long-term system performance during normal and contingency conditions for both steady-state and dynamic conditions utilize realistic performance capabilities of the generators. This should include overexcited and underexcited operation. The TO should periodically review data from real-time operations to confirm that reactive power performance matches the capabilities being used in the simulations of the power system.

Planning Coordinator to Transmission Planner Coordination

PCs, in coordination with their TPs, should develop processes to assure adequate reactive power resource capabilities within their footprints. These processes should include mechanisms to assure that the performance assessments of the transmission system in the planning horizon are based on correct projections of reactive power requirements and reactive power resource capabilities. In general, each TP should plan reactive power resources to match their reactive power requirements (including a system under contingency). Similarly, PCs should assure that the reactive power resource capabilities will meet the reactive power requirements within their footprints.

Planning Coordinator to Planning Coordinator Coordination

PCs should develop processes to assure adequate reactive power resource capabilities within their own footprint and in coordination with adjacent PC areas. These processes should include mechanisms to assure that the periodic assessments of near-term and long-term performance of the transmission system are based on correct projections of reactive power requirements and reactive power resource capabilities. In general, each TO should provide reactive power resource capabilities to match their reactive power requirements. Similarly, in general, each PC should assure that the reactive power resource capabilities within that PC footprint will meet the reactive power requirements within that footprint. Actual reactive energy demand on the boundary between PCs would not be scheduled in actual operation. However, each PC should have the reactive resource “capability” to balance reactive demand under RC direction and TOP control within 30 minutes. In some cases, electrically coherent PCs and their associated PCs may span more than one RC. In such cases, PC(s) should coordinate with multiple RCs. In these cases, the operational implementation plan will affect more than one RC. Both traditional reactive sources and contract demand side management should be under RC/TOP control within 30 minutes. If not, these reactive resources would not be counted as part of the RC/TOP reactive resources. Real-time security analyses should consider reactive power requirements and resource capabilities in the near-term operating environment.

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[49] NERC Reliability Standard MOD-025-2: Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability. Available: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-025-2&title=Verification%20and%20Data%20Reporting%20of%20Generator%20Real%20and%20Reactive%20Power%20Capability%20and%20Synchronous%20Condenser%20Reactive%20Power%20Capability&jurisdiction=United%20States

[50] Modeling Reference Document Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines. Available:https://www.natf.net/docs/natf/documents/resources/natf-reference-document-reporting-and-verification-of-generating-unit-reactive-power-capability-for-synchronous-machines.pdf

Appendix A: Industry Reactive Power Planning Practices

Appendix A provides reactive power planning practices, procedures, and requirements for an array of entities across North America. Each entity provided a brief description and references for their reactive power planning techniques to be used as a reference for other entities. This section includes analysis tools, techniques, planning horizons, and relevant reference materials.[51]

Electric Reliability Council of Texas (ERCOT)

ERCOT Planning Guides provide criteria to maintain a reliable power system, and in particular reliable reactive power planning. There are direct and indirect requirements on all network Elements related to voltage or reactive power. The following are excerpts pulled from the ERCOT Planning Guides, provided here for reference:

- Compliance with NERC Reliability Standard TPL-001-4
- Voltage Support [ERCOT Protocol 3.15]: ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish the ERCOT System Voltage Profile for all Electrical Buses used for Voltage Support in the ERCOT System including synchronous generation capability to maintain a power factor in the range of +/- 0.95, AVR in voltage control, and automatic operating mode. Wind-powered Generation Resources (WGRs) must be capable of producing a defined quantity of Reactive Power to maintain an established Voltage Profile. New Generation is required to have voltage ride through (low- and high- voltage ride through.
- Extended modeling: the ERCOT System consists of those generation and Transmission Facilities (voltages 60 kV and higher) that function as part of an integrated and coordinated system.
- Steady State Voltage Response Criteria [ERCOT Planning Guide 4.1.1.4]
    - In conducting its planning analyses, ERCOT and each TSP shall ensure that all transmission level buses above 100 kV meet the following steady state voltage response and post-contingency voltage deviation criteria:
        - 0.95 – 1.05 pu in the pre-contingency state following the occurrence of any operating condition in category P0 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements.
        - 0.90 – 1.05 pu in the post-contingency state following the occurrence of any operating condition in categories P1 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements.
    - Following the occurrence of any operating condition in categories P1 through P7 of the NERC Reliability Standard TPL-001-4, further analysis to assess voltage stability is required in the event of a post-contingency steady-state voltage deviation that exceeds 8% at any load-serving bus above 100 kV. This is exclusive of buses on a radial system that serve only Resource Entities and/or Load. After further analysis, ERCOT and the TSPs shall endeavor to resolve any voltage instability.
    - If a TSP has communicated to ERCOT that a Facility has unique characteristics and may operate outside of the above ranges and deviation (e.g. Facilities located near a series capacitor) or the Facility needs to be operated in a more restrictive range (e.g. a nuclear plant, UVLS relay settings) or its system is designed to operate with different voltage limits or voltage deviation, then the TSP's specified limits will be considered acceptable.

[51] Nothing in this section is intended as a compliance determination or statement impacting compliance enforcement matters.

- Voltage Stability Criteria [ERCOT Planning Guide 4.1.1.3] - In conducting its planning analyses, ERCOT and each TSP shall ensure that the voltage stability margin is sufficient to maintain post-transient voltage stability under the following study conditions for each ERCOT or TSP-defined area:
  - A 5% increase in Load above expected peak supplied from resources external to the ERCOT or TSP-defined areas and operating conditions in categories P0 and P1 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements; and
  - A 2.5% increase in Load above expected peak supplied from resources external to the ERCOT or TSP-defined areas and operating conditions in categories P2 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements.
- Higher performance for selected contingencies – Some TPL-001-4 contingencies are given a higher system response performance, which translates to a better voltage and reactive profile.
  - P1 performance - A common tower outage is the contingency loss of a double-circuit transmission line consisting of two circuits sharing a tower for 0.5 miles or greater.
  - P1 performance - The contingency loss of a single generating unit shall include the loss of an entire Combined Cycle Train, if that is the expected consequence.
- Regional Reliability Performance Criteria [ERCOT Planning Guide 4.1.1.2]
  - The following performance criteria (summarized in Table 3, ERCOT-specific Reliability Performance Criteria, below) shall be applicable to planning analyses in the ERCOT Region:
    - With all Facilities in their normal state, following a common tower outage, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no nonconsequential Load loss.
    - With any single generating unit unavailable, followed by Manual System Adjustments, followed by a common tower outage, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no nonconsequential Load loss.
    - With any single 345/138 kV transformer unavailable, followed by Manual System Adjustments, followed by a common tower outage, or the contingency loss of a single generating unit, transmission circuit, transformer, shunt device, or FACTS device, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no nonconsequential Load loss. An operational solution may be planned on a permanent basis to resolve a performance deficiency under this condition.
    - Assessments, including proposed solutions, associated with criteria in paragraph (c), above, and line 3 of Table 3 below, shall be completed by no later than May 1, 2015.
  - ERCOT and the TSPs shall endeavor to resolve any performance deficiencies as appropriate. If a Transmission Facility improvement is required to meet the criteria in this Section 4.1.1.2, but the improvement cannot be implemented in time to resolve the performance deficiency, an interim solution may be used to resolve the deficiency until the improvement has been implemented.

Table 3: ERCOT Reliability Performance Criteria [Source: ERCOT]			
Initial Condition	**Event**	**Facilities within Applicable Ratings and System Stable with No Cascading or Uncontrolled Outages**	**Nonconsequential Load Loss Allowed**
Normal System	Common tower outage	Yes	No
Unavailability of a generating unit, followed by Manual System Adjustments	Common tower outage	Yes	No
Unavailability of a 345/138 kV transformer, followed by Manual System Adjustments	Common tower outage; or Contingency loss of one of the following: 1. Generating unit; 2. Transmission circuit; 3. Transformer; 4. Shunt device; or 5. FACTS device	Yes	No

FRCC

The FRCC plans and operates its system to try to ensure that its voltage performance satisfies all equipment limits, stability limits, and Interconnection Reliability Operating Limits (IROL) in the region. In the Planning and Operating horizons, acceptable voltage performance is evaluated with steady-state and transient analysis for expected pre-contingency and post-contingency conditions.

Planning studies are completed in an effort to ensure that all voltages meet the performance criteria detailed in NERC TPL-001-4. Studies also include PV or QV analysis, load flow studies, or dynamic simulations. If these studies result in a new or modified undervoltage load shedding scheme or remedial action scheme, the region reviews and approves it before it becomes operational.

Operating personnel perform studies on a seasonal, monthly, weekly, and day-ahead basis that would identify any voltage issues and if necessary would develop remedies. The RC's EMS continually monitors the system to help ensure that all voltages remain within applicable limits for normal conditions. A real-time contingency analysis tool is used to help ensure that voltages remain within applicable limits for all single contingencies and select multiple-element contingencies. Minimum and maximum voltage limits for facilities within the region are provided to the RC by the TOP. The min/max voltage limits for pre-contingency conditions may be different from the limits for post-contingency conditions.

With all facilities in-service, imports into Florida are limited by thermal overloads or voltage stability; therefore, in addition to load flow analysis, PV analysis is used to help ensure that there is an acceptable margin from the voltage instability point. In the Transmission Planning and Operations Planning horizons, a voltage security factor of 5% for single contingencies and 2.5% for double contingencies is used to provide an active power margin between the voltage collapse point and the Total Transfer Capability (TTC). The voltage collapse point is considered to be an Interconnection Reliability Operating Limit (IROL) since contingencies that occur at transfer levels above that value may result in voltage instability within the FRCC. In the Transmission Planning Horizon, PV analysis is performed for critical single- and multiple-element contingencies to determine the IROL and the Total Transmission Capability. Peak summer and winter base cases are used. In the Operating horizon, PV analysis is performed monthly and daily in PSSE using the latest forecasted loads, scheduled transmission and generation outages and any confirmed transmission transactions for the study period. PV analysis is used to set the monthly and daily TTC if the voltage constraints are more limiting than the thermal constraints. PV analysis also runs automatically in the EMS used by the FRCC RC. The RC receives an alarm if the post-contingency PV margin falls below 200 MW. The RC may also run PV analysis manually if he is aware of upcoming system changes that may affect voltage stability.

Independent System Operator of New England (ISO-NE)

Operational Horizon

ISO New England strives to operate its system to perform acceptably in pre- and post-contingency for a defined set of operating contingencies, within the voltage limits provided by the transmission equipment owners utilizing the regional operating procedures, guidelines, and standards. Voltage limits include both low and high limits, and are time dependent. Equipment owners can provide any or all of the normal and emergency voltage limits defined for use, which may be effective continuously (normal), over a long time duration (long time emergency, or LTE[52]), a shorter duration (short time emergency, or STE – a 15 minute limit), or brief duration for emergent concerns (drastic action limit, or DAL – a 5 minute limit). The possibility of voltage collapse is also recognized and used in determining steady state limits while operating the system.

ISO-NE examines system voltage / reactive needs in the operations horizon from two or more years out up to real-time. Long term studies focus on determining system voltage / reactive needs in defined portions of New England, how reactive resources should be utilized to meet voltage limits under all potential stresses (peak, intermediate, and light load conditions; with and without heavy transfers) under defined single contingency (N-1) or multiple contingency (N-1-1[53]) events. This longer term operational planning analysis also examines and documents the envelope of acceptable load power factor required to attain acceptable transmission system performance over the continuum of system conditions. This load power factor requirement information is provided to the local distribution companies to allow them to adjust and change their reactive compensation programs, at the distribution level, to provide integrated reactive power support with local transmission / generation facilities and maintain system reliability. These analyses also provide a feedback path into the transmission planning process when they find reactive resource deficiencies that cannot be met with the existing portfolio of reactive resources.

These operational reactive power planning efforts support other operational evaluations of system reactive needs. These analyses focus on analyzing and capturing, in transmission operating guide form, any unit commitment or defined reactive resource use for reliability needs for N-0 and N-1 conditions. These include voltage / reactive issues ranging from peak load / low voltage concerns to minimum load / high voltage concerns. The analyses may also support the creation or revision of operator tools and aids in monitoring system voltage / reactive performance for the transmission operating guides in outage coordination and real-time operations.

These voltage / reactive evaluations are continued through the outage coordination process, which allows outages to be provided by asset owners, and evaluated by local and ISO-NE outage coordination staff, up to two years out. ISO-NE's outage coordination staff (both short term and long term) performs AC power flow analyses for forecast loads, generation, system transfers and scheduled / approved outages, and identifies any voltage / reactive issues. They propose solutions (i.e. reactive resource posturing, generation dispatch, outage re-scheduling) and request, as needed, additional engineering analysis support. The engineering support can result in outage topology

[52] Voltage limit LTE varies by TO based on each TO's methodology and risk tolerance.

[53] N-1-1 contingencies are the consecutive loss of two Elements where redispatch is allowed between events; N-2 contingencies are the simultaneous loss of two Elements.

dependent operating guidance, which may take the form of operational guidance on the outage application, or a temporary operating guide, which describes the operating actions required for reliable operation during the defined outage scenario. These actions / limits are used by operators in real-time, as well as their real-time tools, which perform real-time AC contingency analysis, reactive reserve monitoring and voltage transfer limit evaluations. Voltage schedules for significant generation and transmission reactive assets are monitored in real-time to support acceptable system voltage and stability performance. Deviations from the defined upper and lower limit voltage schedule bands are alarmed and acted upon by ISO operators to maintain system security.

Planning Horizon

ISO-NE strives to plan its system consistent with NERC, NPCC[54], and ISO-NE[55] planning criteria, with additional guidance provided by the ISO-NE Transmission Planning Technical Guide[56] ("Technical Guide"). Section 4 of the Technical Guide describes the voltage criteria used in planning the system.

Voltage standards have been established to satisfy three constraints: maintaining voltages on the distribution system and experienced by the end-use load customers within required limits, maintaining voltages for transmission equipment and equipment connected to the transmission system within that equipment's rating, and avoiding voltage collapse. Generally the maximum voltages are limited by equipment and the minimum voltages are limited by customer requirements and voltage collapse. The standards apply to networked facilities operated at a nominal voltage of 69 kV or above.

The voltage standards prior to equipment operation apply to voltages at a location that last for seconds or minutes, such as voltages that occur prior to transformer load tap changer ("LTC") operation or capacitor switching. The voltage standards prior to equipment operation do not apply to transient voltage excursions such as switching surges, or voltage excursions during a fault or during disconnection of faulted equipment.

Pre-Contingency Voltages

The voltages at all networked buses must be in the range of 0.95-1.05 pu with all lines in service. There are two exceptions to this requirement. The first is voltage limits at nuclear units, which are described below. The second exception is that higher voltages are permitted at buses where the affected TO has determined that all equipment at those buses is rated to operate at the higher voltage. Often the limiting equipment under steady-state high voltage conditions is a circuit breaker. Maximum breaker voltages are based on IEEE Standard C37.06[57].

[54] https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

[55] http://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp03/pp3_final.pdf

[56] http://www.iso-ne.com/static-assets/documents/2016/01/planning_technical_guide_1_15_16.pdf

[57] IEEE Standard for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities for Voltages Above 1000 V, IEEE Standard C37.06-2009, 2009.

Table 4: Maximum Operating Voltages for Breakers

Breaker Nominal Voltage [kV]	Maximum Operating Voltage [kV]
345	362
230	245
138	145
115	123*
69	72.5

* Older 115kV breakers may have different maximum voltage limits.

For N-1 contingencies, shunt VAR devices are modeled in or out of service pre-contingency, to prepare for high or low voltage caused by the contingency, as long as the pre-contingency voltage standard is satisfied. For testing of an N-1-1 contingency, shunt VAR devices are switched between the first and second contingencies to prepare for the second contingency as long as the post-contingency voltage standard is satisfied following the first contingency and prior to the second contingency.

Post-Contingency Low Voltages Prior to and After Equipment Operation

The lowest post-contingency voltages at all networked buses must be equal to or higher than 0.90 pu prior to the automatic or manual switching of shunt or series capacitors and reactors, and operation of tap changers on transformers, autotransformers, phase-shifting transformers and shunt reactors. Dynamic devices such as generator voltage regulators, STATCOMs, SVCs, and HVDC equipment are assumed to have operated properly to provide voltage support when calculating these voltages. Also capacitor banks that switch automatically with no intentional time delay (switching time is the time for the sensing relay and the control scheme to operate, usually a few cycles up to a second) may be assumed to have operated when calculating these voltages. No N-1 or N-1-1 contingency (described in Technical Guide Sections 12.4 and 12.5) is allowed to cause a voltage collapse.

Lowest bus voltages at all networked buses must be greater than or equal to 0.95 pu after switching of shunt or series capacitors and reactors, and operation of transformer tap changers, autotransformers, and phase-shifting transformers. There are two exceptions to this standard. The first is voltage limits at nuclear units. The other exception is that voltages as low as 0.90 pu are allowed at a limited number of networked buses where the affected TO has confirmed that the associated lower voltage system has been designed to accept these lower voltages and where the change in voltage pre-contingency to post-contingency is not greater than 0.1 pu.

Post-Contingency High Voltages Prior to and After Equipment Operation

ISO-NE is currently developing a standard for high voltages prior to corrective action. After equipment operation, the highest voltages at all networked buses must be equal to or lower than 1.05 pu. The only exception is that higher voltages are permitted where the affected TO has confirmed that all equipment at those buses is rated to operate at the higher voltage.

Voltage Limits for Line End Open Contingencies

There is no minimum voltage limit for the open end of a line if there is no load connected to the line section with the open end. If there is load connected the above standards for post-contingency low voltage apply. ISO-NE is currently developing a standard for the maximum voltage limit for the open end of a line.

Transient Voltage Response

ISO-NE employs the criteria described in Appendix E of the Technical Guide[58].

Voltage Limits at Buses Associated with Nuclear Units

The minimum voltage requirements at buses serving nuclear units are based on Nuclear Plant Licensing Requirements (NPLRs) and are identified to the Transmission Entities (TE) and the Nuclear Plant Generator Operator (NPGOP) in the mutually agreed to Nuclear Plant Interface Requirements (NPIRs). These pre-contingency and post contingency voltage requirements are derived from Design Basis Accident studies required by the NRC to ensure plant safe shutdown when the generator is online or shutdown. Actions for maintaining and recovering voltage include but are not limited to switching of capacitors and operation of transformer load tap changers to ensure the limits are maintained. These limits are documented as Nuclear Plant Interface Requirements (NIPRs) for each nuclear station.

[58]Available: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_e_voltage_sag_guideline.pdf

MISO Energy

MISO's voltage and reactive power assessment, control, coordination and planning practices are largely governed by the following two documents:

- Voltage and Reactive Power Management Business Practice Manual (BPM-020), and
- Transmission Planning Business Practices Manual[59] (BPM-018)

These documents outline the voltage and reactive power management processes undertaken by MISO and the companies within the MISO footprint in an effort to meet and go beyond the requirements of the NERC Reliability Standards such as the TOP, TPL and VAR standards. These documents also note the roles and responsibilities of MISO and its member companies in analyzing, maintaining, monitoring, and controlling voltage levels, reactive resources, and reactive power flows within the MISO footprint. Specifically, as it pertains to voltage and reactive power, the complementary roles of MISO as the RC and the TOPs and GOPs are delineated.

Voltage and Reactive Power Planning: MISO strives to ensure efficient and reliable system operations through detailed evaluations and assessments performed for a range of system conditions from real-time operations to the long-term planning horizon covering the next 10 years. Analyses performed typically include:

- Steady-state contingency analyses
- Transient stability/dynamics analyses
- Transfer studies
- PV/QV analyses
- Static/dynamic real-time reactive power reserves calculations
- Generator interconnection and deliverability analyses

Voltage Coordination: Conflicting voltage levels and set-points/targets on neighboring systems can cause operational issues as well as incorrect planning of the system. MISO works with its neighbors to develop coordinated reactive power and voltage management policies to ensure the mutual objectives of ensuring system reliability and efficiency are fulfilled.

Peak Reliability

Peak uses a real-time voltage stability tool, V&R Energy ROSE software, and uses PV and QV analysis for all identified IROLs. These are used to calculate the reactive margin for specific buses. Peak will be extending this analysis for other Paths that might have voltage stability issues.

Peak monitors system bus voltages WECC-wide in real-time in the EMS state estimator and using RTCA for N-1 contingency analysis. These voltages are compared against their respective limits. Voltage limits are also monitored for all operational planning studies (next day, near real-time). The limits are provided by the Balancing Authorities and TOPs.

[59] https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

PJM Interconnection

Operational horizon

PJM strives to direct the operation of the PJM system according to approved NERC Reliability Standards. In doing this, PJM considers transmission constraints, restrictions, and/or limitations in the overall operation of the PJM RTO. The PJM RTO seeks to operate such that the following are not exceeded:

- Transmission facility thermal limits
- Voltage limits
- Transfer limits
- Stability limits
- IROLs

The PJM RTO seeks to operate so that loading on all PJM SOLs are within normal continuous ratings, and so that immediately following any single facility malfunction or failure, the loading on all remaining facilities can be expected to be within emergency ratings.

This principle requires that action be taken before a malfunction or failure occurs in order to control post-contingency loading on a pre-contingency basis. In addition to traditional thermal limitations; PJM operates the PJM RTO considering voltage and stability related transmission limits. These limitations are:

- **Voltage Limits:** High, Low, and Load Dump actual voltage limits, high and low emergency voltage limits for contingency simulation, and voltage drop limits for wide area transfer simulations to protect against wide area voltage collapse.
- **Transfer Limits:** The MW flow limitation across an interface to protect the system from large voltage drops or collapse caused by any viable contingency.
- **Stability Limits:** Limit based on voltage phase angle difference to protect portions of the PJM RTO from separation or unstable operation.

PJM works to operate the facilities that are under PJM's operational control such that no PJM monitored facility will violate normal voltage limits on a continuous basis and that no monitored facility will violate emergency voltage limits following any simulated facility malfunction or failure. Typically, high voltage emergency limits are equipment-related while low voltage limits are system-related.

Transfer Limits (Reactive/Voltage Transfer Limits)

Post-contingency voltage constraints can limit the amount of energy that can be imported from and through portions of the PJM RTO. PJM utilizes a real-time Transfer Limit Calculator (TLC) Program within the PJM EMS System to evaluate the reactive interface for voltage instability. TLC is utilized to establish inter-regional and intra-regional Transfer Capability and to determine Transfer Limits for the use in real-time operation.

Stability Limits

The PJM RTO established stability limits for preventing electrical separation of a generating unit or a portion of the PJM RTO. PJM recognizes three types of stability:

- **Steady State Stability:** A gradual slow change to generation that is balanced by load.
- **Transient Stability:** The ability of a generating unit or a group of generating units to maintain synchronism following a relatively severe and sudden system disturbance. The first few cycles are the most critical time period.

- **Dynamic Stability:** The ability of a generating unit or a group of generating units to damp oscillations caused by relatively minor disturbances through the action of properly tuned control systems.

PJM seeks to operate the facilities that are under PJM operational control such that the PJM system will maintain angular and voltage stability following any single facility malfunction or failure. PJM utilizes a real-time Transient Stability Assessment (TSA) tool that interfaces with the PJM EMS System to perform this analysis in real-time. PJM Manual 3 "Transmission Operations" discusses specific transmission conditions and procedures for the management of transmission facilities within the PJM control area.

Planning Horizon

PJM's most fundamental responsibility is to plan and operate a safe and reliable Transmission System that serves all long term firm transmission uses on a comparable and not unduly discriminatory basis. This responsibility is addressed by PJM Regional Transmission Expansion Planning (RTEP) reliability planning. Reliability planning is a series of detailed analyses that ensure reliability under the most stringent of the applicable NERC, PJM or local criteria.

Reliability planning involves a near-term and a longer term review. The near term analysis is applicable for a period of 5 years out from the current year. The longer term view is applicable for a period of 6 to 15 years out from the current year. Each review entails multiple analysis steps subject to specific criteria that depends on the facilities and the type of analysis being performed.

Reactive power planning is accomplished via the PJM RTEP process. The robustness of the PJM network is achieved by conducting analysis over a wide range of system conditions. This includes a Reference case, seasonal analysis, a load deliverability analysis, and a generation delivery analysis. There are several steps in an annual near-term reliability review including Baseline, Load Deliverability, Generation Deliverability, and Stability Analysis.

Baseline Analysis

The reference power flow case and the analysis techniques comprise the full set of analysis assumptions and parameters for reliability purposes. Baseline analysis is a thorough analysis of the reference power flow to ensure adequacy based on normal (applicable to system normal conditions prior to contingencies) and emergency (applicable after the occurrence of a contingency) thermal limits or voltage criteria. It is based on a 50/50 load forecast from the latest available PJM Load Forecast Report (50% probability that the actual load is higher or lower than the projected load).

- **Load Deliverability Analysis:** Suite of tests to ensure that the Transmission System provides adequate deliverability of power flow to each load area's requirements from the aggregate of system generation. The tests use an array of probabilistic dispatches to determine "expected loading" to determine thermal limits. A deterministic dispatch method is used to create imports for the voltage criteria test. The Transmission System reliability criterion used is 1 failure event in 25 years. This is intended to design transmission so that it is not more limiting than the generation system which is planned to a reliability criterion of 1 failure event in 10 years.

- **Generation Deliverability Analysis:** The Generation Deliverability test ensures that, consistent with the load deliverability single contingency testing procedure, the Transmission System is capable of delivering the aggregate system generating capacity at peak load with all firm transmission service modeled. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified capacity resources in each "area".

PJM Manual 14[60] series (14a, 14b, 14c, 14d, and 14e) provides information regarding PJM's Planning Process. Details of the Transmission Planning Process are contained in manual 14b.

Southern Company

Satisfactory voltage performance is determined by evaluating steady-state and transient voltages during normal, contingency, and post-contingency conditions. This evaluation covers projected system load levels and conditions in the Planning horizon. Power flow analysis is performed to assess the system during steady-state conditions. The general steady-state screening criteria for post-contingency networked 300kV and below BES transmission buses are as follows:

- Voltage magnitudes are planned to be in the range of .95-1.05 pu for P0 no contingency conditions
- Voltage magnitudes should generally be in the range of 0.92-1.05 pu for P1-P2 single contingencies
- Voltage magnitudes should generally be in the range of 0.90-1.05 pu for P3-P7 multiple contingencies
- For load serving stations with voltage regulation equipment, the voltage deviation should be less than 8%
- For load serving stations without voltage regulation equipment, the voltage deviation should be less than 5%

The screening criteria for 500kV transmission buses is generally 0.97 – 1.075 pu for all Planning Events (P0-P7).

Bus voltages found in the power flow analysis which do not meet these guidelines will generally result in the addition of static reactive resources to the system.

In addition to power flow analysis, a static voltage stability analysis is performed using the so-called PV curve technique. Voltage instability is defined as the knee of the PV curve. The system is planned such that it will operate with 5% or greater margin from the voltage instability point for P1-P2 single contingencies and for P3 contingencies. For other contingencies resulting in taking out multiple elements/units (P4-P7), voltage stability margins should be 2.5% or greater from the voltage instability point.

Transient voltage stability is evaluated using time-domain simulations which model the dynamic behavior of induction motor loads. Appropriate voltage recovery criteria for post-contingency networked transmission buses are used to determine the adequacy of voltage resources. When voltages do not recover sufficiently, dynamic var sources are generally added to the system.

[60] PJM Manual 14 Series. Available: http://www.pjm.com/~/media/documents/manuals/m14b.ashx

Appendix B: Transient Voltage Response Criteria Practices

Appendix B details transient voltage response criteria for various entities, as reported for inclusion in this guideline. These criteria are provided here for industry reference. Each entity has provided their transient voltage response criteria that was developed in an effort to comply with NERC Reliability Standard TPL-001-4 Requirement R5.[61]

Electric Reliability Council of Texas (ERCOT)

Transient voltage response criteria is defined in ERCOT Planning Guide 4.1.1.5 Transient Voltage Response Criteria. In conducting its planning analyses, ERCOT and each TSP shall ensure that all transmission level buses above 100 kV meet the following transient voltage response criteria:

1. For any operating condition in category P1 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, voltage shall recover to 0.90 pu within five seconds after clearing the fault.
2. For any operating condition in categories P2 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, voltage shall recover to 0.90 pu within ten seconds after clearing the fault.

Contingency P1 has a high probability of occurrence and it is recommended a quicker voltage recovery response than the group of contingencies in P2 to P7, which have a lower probability of occurrence.

Voltage Ride Through Capability

Voltage Ride Through (VRT) requirements in ERCOT specify that a Generation Facility must not disconnect during transients, following a voltages vs. times profile. Figure 21 provides an example of the ERCOT VRT curve for Intermittent Renewable Resources (IRR). This requirement prescribes that the generator voltage protective relays must be set according to the VRT Standard. Dynamic reactive devices will inject or absorb reactive power automatically to satisfy the VRT requirement. Low voltage ride through (LVRT) requirements are generally accepted by industry. Now, High voltage ride through (HVRT) is equally important but less understood because its need becomes important for regions under specific operating conditions. For regions with low load conditions and large penetration of renewable power (wind or solar) a transmission contingency will reduce the loading of the network, causing higher transmission line charging being injected into the network, resulting in higher bus voltages. These higher voltage could cause generation to disconnect due to protection relay tripping on high voltage, feeding the high voltage condition by losing leading reactive support from such tripped generation. These events could induce a cascade of generation tripping on high voltage. Hence, the HVRT standard serve as a way to support injection of leading reactive power into the grid while LVRT supports injection of lagging reactive power into the grid.

[61] Nothing in this section is intended as a compliance determination or statement impacting compliance and enforcement matters.

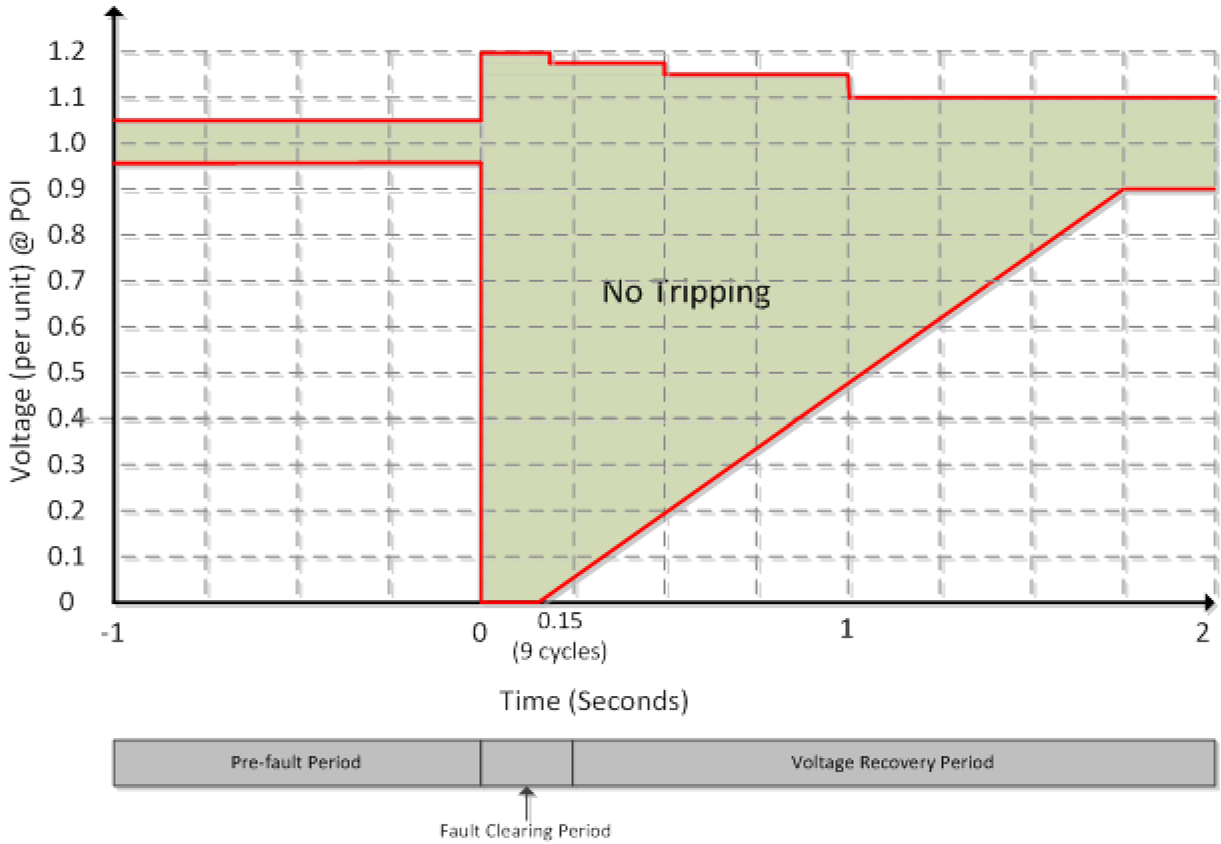


Figure 21: ERCOT Voltage Ride Through Profile [Source: ERCOT]

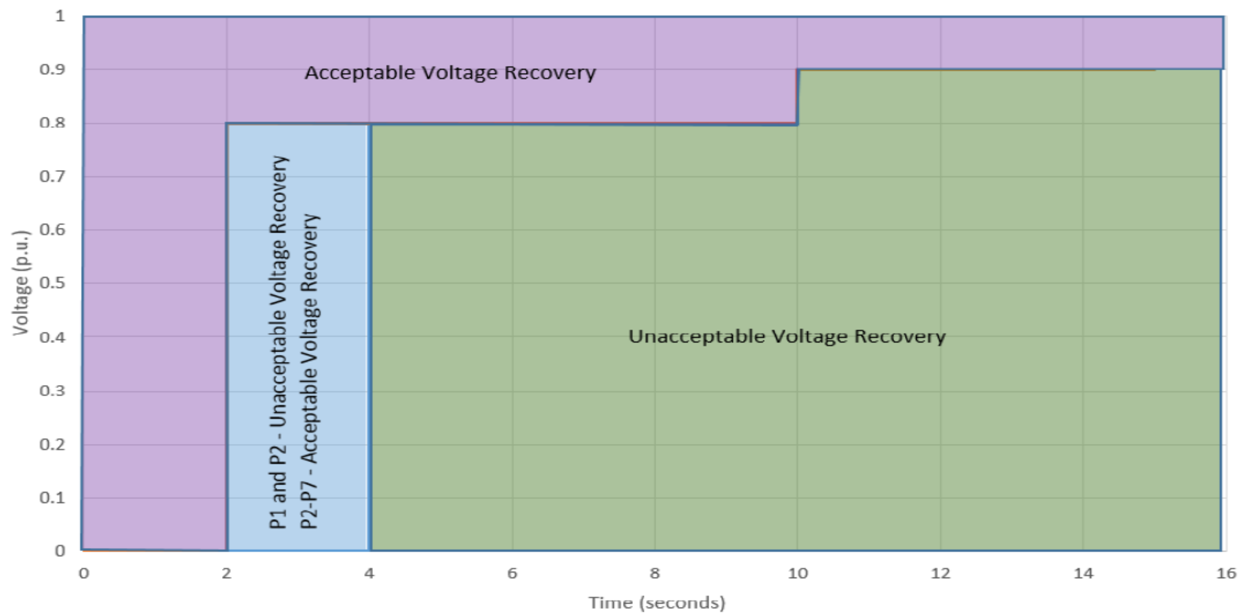
FRCC

The FRCC transient voltage criteria are the same for all TPs within the region. The transient voltage response criteria applies to the time period immediately following fault clearing or any other event being simulated. During this time period there may be depressed voltages and voltage swings due to the event. The transient voltage dip criteria are intended to indicate unacceptably sluggish voltage recovery after an event.

FRCC's transient voltage response criteria are summarized below. Times in Table 5 are seconds after fault clearing. In the plot below, 0 seconds corresponds to the moment of fault clearing. The FRCC transient voltage response criteria are applicable only to planning events P1 – P7 and only at load buses. FRCC plans and evaluates the low voltage ride through capability at generator buses using the PRC-024 criteria as discussed above in response to R4.3.1.2.

Table 5: FRCC Transient Voltage Response Criteria

Planning Events P1-P2		Planning Events P3-P7	
Load Bus Voltage Must Recover To [pu]	At or Before Time [sec]	Load Bus Voltage Must Recover To [pu]	At or Before Time [sec]
0.8	2.0	0.8	4.0
0.9	10.0	0.9	10.0



Note: Zero seconds corresponds to the time at which a fault is cleared.

Figure 22: FRCC Transient Voltage Response Criteria Profile [Source: FRCC]

Independent System Operator of New England (ISO-NE)

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 limits are supported by the typical sag tolerances shown in Figures C.5 to C.10 in IEEE Standard 1346-1998.

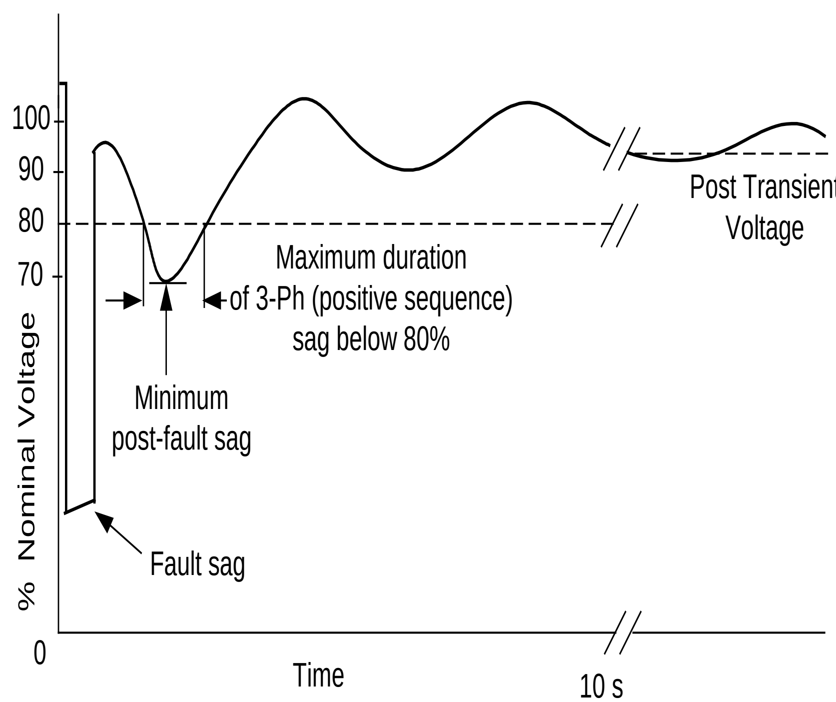


Figure 23: Transient Voltage Sag Parameters [Source: ISO-NE]

MISO Energy

MISO has established standard voltage criteria for planning and operating the transmission system. These criteria are informed by guidelines and criteria used by MISO member companies, who are also NERC registered entities (TOPs, TPs, TOs, etc.) Members may request MISO to monitor voltage and reactive power performance on their system based on criteria different (more stringent) than the standard criteria established by MISO. Transient voltage monitoring criteria are specified in BPM-020. MISO member TO planning criteria are available at https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=433.

Voltage criteria are used during steady-state and transient stability analyses performed for system planning, outage coordination, operational planning, and real-time operation studies. The voltage criteria are periodically reviewed with the member companies as needed to ensure they are current.

PJM Interconnection

PJM planning analysis ensures the system is transiently stable and that all system oscillations display positive damping. Stability studies are performed for critical system conditions, which include light load and peak load for three phase faults with normal clearing plus single line to ground faults with delayed clearing. Also, specific TO designated faults are examined for plants on their respective systems. The quantities monitored for generator stability include:

- Generator rotor angles and speed;
- Generator active power output;
- Generator field voltage (EFD) and terminal voltage; and
- Bus voltages magnitudes in the same area.

Acceptable Damping:
Following the disturbance, the oscillations of the monitored parameters must display positive damping, calculated with a damping coefficient calculation algorithm. This characterizes the degree of positive (damped) or negative (undamped) damping based on the trend, over the duration of the stability run, of the envelope of machine angle oscillation peaks. This trend can be observed by drawing an envelope connecting each succeeding peak or valley of the oscillation of the monitored element. An acceptable oscillation envelope will demonstrate a positive decay within the appropriate test period (normally 10 to 15 seconds). A sustained oscillatory system response, even if slightly damped, will cause the system to be in a vulnerable state and exposed to adverse impacts for subsequent changes to the system over a prolonged time. To limit this system exposure, PJM uses a 3% damping ratio margin. Such positive damping demonstrates an acceptable response by the system, and no further analysis is required

Acceptable Transient Voltage Recovery:
When a fault occurs on the transmission system, system voltages are temporarily reduced. Once the fault is cleared, voltages follow transient voltage recovery trajectories governed by system dynamics. The transient voltage recovery criteria should be satisfied at BES buses. Regardless of the load model that is selected, the voltage following fault clearing shall recover to a minimum of 0.7 pu after 2.5 seconds. If a plant-specific document (such as Nuclear Plant Interface Coordination (NPIR)) or local TO specific planning criteria requires a more conservative voltage recovery criterion, that specific criterion will be applied.

Generator Ride Through Capability:
PJM evaluates the voltage ride through capability at generator buses as specified in PRC-024 or applicable TO criteria which require GOs set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

Southern Company

Southern Company uses different criteria based on peak versus off-peak study conditions and differentiates criteria based on type of contingency studied. Below are descriptions of the criteria for different system conditions:

Criteria for Peak Load Stability Studies:

- For normally-cleared, three-phase fault contingencies (P1-P3), the transient voltage response criteria is the following: all transmission networked buses must recover above 80% voltage within 2 seconds of the initial fault.
- For P4-P7 and Extreme contingencies, the transient voltage response criteria is the following: all transmission networked buses must recover above 80% voltage within 4 seconds of the initial fault.

Criteria for Off-Peak Stability Studies (50% of Peak Load):

- For normally-cleared, three-phase fault contingencies (P1-P3), voltages must not stay below 80% for more than 40 cycles (transient voltage dip).
- No transient voltage response criteria are used for P4-P7 and Extreme contingencies.

For peak load studies, a complex load model which includes induction motors effects is used. The rationale behind the 2-second response criteria for the higher probability contingencies (normally-cleared, three-phase fault) is:

1. IEEE 45 (IEEE Recommended Practice for Electrical Installations on Shipboard) provides a precedent for a 2 second recovery criterion.
2. Various IEEE technical papers documenting induction motor testing which indicate that a voltage recovery greater than 2 seconds could result in a large percentage of stalled motors.

By choosing this criteria, the loss of load is minimized for higher probability contingencies. For lower probability contingencies, the criteria is to recover above 80% in 4 seconds. For these lower probability contingencies, some loss of load is considered to be acceptable.

For off-peak studies, voltage recovery is rarely an issue. A ZIP load model is used for these studies. The transient voltage dip criteria is intended to flag cases where a more complex load model might contribute to an angular stability issue.

Southwest Power Pool (SPP)

SPP requires that after the fault is cleared bus voltages on the Bulk Electric System shall recover above 0.70 pu within 2.5 seconds. Bus voltage shall not swing above 1.20 pu after the fault is cleared, unless affected transmission system elements are designed to handle the rise above 1.2 pu. Figure 24 shows this criteria visually[62].

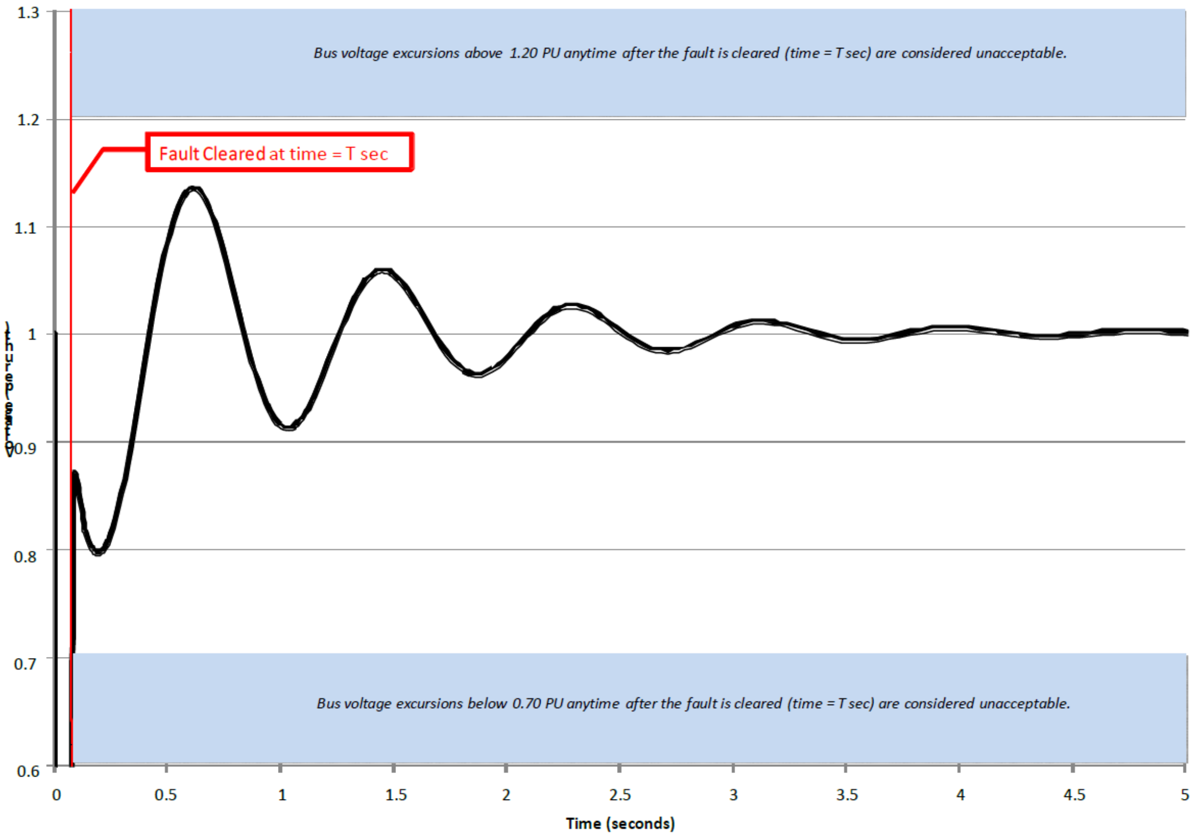


Figure 24: SPP Transient Voltage Recovery Requirement Illustration [Source: SPP]

Peak Reliability

Peak also monitors transient voltage response for online transient stability assessment. While there are no operational requirements related to transient voltage response, Peak is working with the WECC entities to determine an appropriate voltage response level based on expected consequences of delayed voltage recovery or severe voltage dips (e.g., based on under- or overvoltage relay settings).

[62]Available: http://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements_twg%20approved%2012_16_2015.pdf

Errata

March 7, 2017

Page 7: Figures 5 and 6: STATCOM and SVC figures updated to a voltage-current (V-I) characteristic.