Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

PRC-024-3 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	December 2018
SAR posted for comment	December 2018 – January 2019
Standards Committee accepted the revised SAR	February 2019
45-day formal comment period with ballot	April – May 2019
45-day formal or informal comment period with additional ballot	September – November 2019

Anticipated Actions	Date
10-day final ballot	December 2019
Board adoption	February 2020

A. Introduction

1. **Title:** ~~Generator~~ **Frequency and Voltage Protecti~~ve~~on ~~Relay~~ Settings** for Generating Resources

2. **Number:** PRC-024-~~2~~3

3. **Purpose:** ~~Ensure Generator Owners~~To set ~~their generator~~ protecti~~ve~~on ~~relays~~ such that generating resource(s) ~~units~~ remain connected during defined frequency and voltage excursions in support of the Bulk Electric System (BES).

4. **Applicability:**

4.1. ~~Generator Owner~~Functional Entities:

4.1.1 Generator Owners that apply protection listed in Section 4.2.1.

4.1.2 Transmission Owners (in the Quebec Interconnection only) that own a BES generator step-up (GSU) transformer or main power transformer (MPT)[1] and apply protection listed in Section 4.2.1.

4.1.3 Planning Coordinators (in the Quebec Interconnection only)

4.2. Facilities[2]:

4.2.1 Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the generating resource(s); or (ii) provide signals to the generating resource(s) to either trip or cease injecting current; and are applied to the following:

4.2.1.1 BES generating resource(s).

4.2.1.2 BES GSU transformer(s).

4.2.1.3 High side of the generator-connected unit auxiliary transformer[3] (UAT) installed on BES generating resource(s).

4.2.1.4 Individual dispersed power producing resource(s) identified in the BES Definition, Inclusion I4.

4.2.1.5 Elements that are designed primarily for the delivery of capacity from the individual dispersed power producing resources

[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.

[2] It is not required to install or activate the protections described in Facilities Section 4.2.

[3] These transformers are variably referred to as station power UAT, or station service transformer(s) used to provide overall auxiliary power to the generating resource(s). This UAT is the transformer connected on the generator bus between the low side of the GSU and the generator terminal.

identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.6 MPT[4] of resource(s) identified in the BES Definition, Inclusion I4.

4.2.2 **Exemptions:** Protection on all auxiliary equipment within the generating Facility.

5. **Effective Date:** See the Implementation Plan for PRC-024-~~2~~3.

[4] For the purpose of this standard, the MPT is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources

~~D.~~B. Requirements and Measures

R1. Each Generator Owner shall set its applicable frequency protection[5] ~~that has generator frequency protective relaying [1] activated to trip its applicable generating unit(s) shall set its protective relaying~~ in accordance with PRC-024 Attachment 1 such that the ~~generator frequency protective relaying does not trip the~~ applicable ~~generating unit(s)~~ protection does not cause the generating resource to trip or cease injecting current within the "no trip zone" ~~of PRC-024 Attachment 1, subject to~~ during a frequency excursion with the following exceptions:~~[2]~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- ~~Generating unit(s)~~ Applicable frequency protection may ~~may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending~~ be set to trip or cease injecting current within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.~~actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.~~

~~Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).~~

M1. ~~Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance~~

[5] Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the generating resource(s); or (ii) provide signals to the generating resource(s) to either trip or cease injecting current.

~~[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.~~

~~[2] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.~~

~~[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.~~

~~[4] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.~~

~~with Requirement R3.~~Each Generator Owner shall have evidence that the ~~generator~~ applicable frequency protecti~~ve~~on ~~relays~~ ha~~ve~~s been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

~~R3.~~R2. Each Generator Owner shall set its applicable voltage protection[5] in accordance with PRC-024 Attachment 2, ~~that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying~~ such that ~~the generator voltage protective relaying does not trip~~ the applicable protection does not cause the generating resource to trip or cease injecting current within the "no trip zone" during a voltage excursion at the high side of the GSU or MPT,~~generating unit(s) as a result of a voltage excursion (at the point of interconnection[3]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[4] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is~~ subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2, then the Generator Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- ~~Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).~~
- ~~Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).~~
- ~~Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.~~
- ~~Generating unit(s) may~~Applicable voltage protection may be set to trip or cease injecting current during a voltage excursion within a portion of the "no trip zone" ~~of PRC-024 Attachment 2~~ for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner shall have evidence that ~~generator~~applicable voltage protecti~~ve~~on ~~relays~~ has~~ve~~ been set in accordance with Requirement R2, such as dated setting sheets, voltage-time ~~curves~~boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

~~R4.~~**R3.** Each Generator Owner shall document each known regulatory or equipment limitation[6] that prevents an applicable generating resource(s)~~unit~~ with ~~generator~~ frequency or voltage protecti~~ve~~on ~~relays~~ from meeting the ~~relay~~ protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~4.1.~~**3.1.** The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations ~~(excluding limitations noted in footnote 3)~~ that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3, such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

~~R6.~~**R4.** Each Generator Owner shall provide its applicable ~~generator~~ protection ~~trip~~ settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated ~~unit~~ generating resource(s) within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested ~~trip~~ settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of ~~relay~~ protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~M3.M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.~~

[6] Excludes limitations ~~that are~~ caused by the setting capability of the ~~generator~~ frequency, ~~and~~ voltage, and volts per hertz protective relays ~~themselves~~ for the generating resource(s). This~~but~~ does not exclude limitations originating in the equipment ~~that they~~ protected by the relay. This also does not exclude limitations of frequency, voltage, and volts per hertz protection embedded in control systems.

~~M4.~~M1. ~~Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.~~

~~M5.~~M1. ~~Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.~~

M4. Each Generator Owner shall have evidence that it communicated applicable ~~generator protective relay trip~~protection settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

~~E.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

~~1.3.~~ ~~Data~~ Evidence Retention:

1.2. The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-~~-~~time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Generator Owner shall ~~retain~~ keep data or evidence ~~of compliance with~~ Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.
- If a Generator Owner is found non-compliant, the Generator Owner or Transmission Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

~~1.6.~~1.3. **Compliance Monitoring and Assessment ~~Processes~~Program:** As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigations~~

~~Self-Reporting~~

~~Complaint~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Generator Owner ~~that has~~failed to set its applicable frequency protection ~~activated to trip a generating unit, failed to set its generator frequency protective relaying~~ so that it does not trip ~~within the criteria listed in~~ or cease injecting current according to Requirement R1 ~~unless there is a documented and communicated regulatory or equipment limitation per Requirement R3~~.
R2.	N/A	N/A	N/A	The Generator Owner ~~with voltage protective relaying activated to trip a generating unit,~~ failed to set its applicable voltage ~~protective relaying~~protection so that it does not trip ~~as a result of a voltage excursion at the point of interconnection, caused by an event external~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~to the plant per the criteria specified in~~ or cease injecting current according to Requirement R2 ~~unless there is a documented and communicated regulatory or equipment limitation per Requirement R3~~.
R3.	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.

<table>
<tr><th rowspan="2">R #</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td>R4.</td><td>The Generator Owner provided its ~~generator~~ protection ~~trip~~ settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those ~~trip~~ settings.

OR

The Generator Owner provided ~~trip~~ protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.</td><td>The Generator Owner provided its ~~generator~~ protection ~~trip~~ settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those ~~trip~~ settings.

OR

The Generator Owner provided protection ~~trip~~ settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.</td><td>The Generator Owner provided its ~~generator~~ protection ~~trip~~ settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those ~~trip~~ settings.

OR

The Generator Owner provided protection ~~trip~~ settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.</td><td>The Generator Owner failed to provide its ~~generator~~ protection ~~trip~~ settings within 150 calendar days of any change to those ~~trip~~ settings.

OR

The Generator Owner failed to provide protection ~~trip~~ settings within 150 calendar days of a written request.</td></tr>
</table>

~~F.~~D. Regional Variances

~~None~~

D.A. Variance for the Quebec Interconnection

This Variance extends the applicability of Requirements R1, R3, and R4 to Transmission Owners in the Quebec Interconnection that own a BES GSU or MPT and apply protection listed in Section 4.2.1, Facilities. This Variance also replaces Requirement R2 of the continent-wide standard in its entirety and adds a new requirement, Requirement D.A.5., applicable to Planning Coordinators in the Quebec Interconnection.

In Requirements R1, R3, and R4, all references to "Generator Owner" are replaced with "Generator Owner and Transmission Owner."

This Variance replaces continent-wide Requirement R2 in its entirety with the following:

D.A.2. Each Generator Owner and Transmission Owner shall set its applicable voltage protection[5] in accordance with PRC-024 Attachment 2a, such that the applicable protection does not cause the generating resource to trip or cease injecting current during a voltage excursion within the "no trip zone" at the high side of the GSU or MPT, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- For newly designated strategic power plants, applicable protections must comply with the high voltage durations for such plants within 48 calendar months of the notification made pursuant to Requirement D.A.5. During this transition period, voltage protections must at least comply with the high voltage durations for "all power plants".
- The generating resource(s) are permitted to be set to trip or to cease injecting current during a voltage excursion bounded by the "no trip zone" of PRC-024 Attachment 2a for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2a, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Inverter-based resources voltage protection settings may be set to cease injecting current momentarily during a voltage excursion at the

high side of the MPT, bounded by the "no trip zone" of PRC-024 Attachment 2a, under the following conditions:

- After a minimum delay of 0.022 s, when the positive-sequence voltage exceeds 1.25 per unit (p.u.) Normal operation must resume once the voltage drops back below 1.25 p.u at the high side of the MPT.
- After a minimum delay of 0.022 s, when the phase-to-ground root mean square (RMS) voltages exceeds 1.4 p.u., as measured at generator terminals, on one or multiple phases. Normal operation must resume once the positive-sequence voltage drops back below the 1.25 p.u. at the high side of the MPT.

M.D.A.2. Each Generator Owner and Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

This Variance adds the following Requirement:

D.A.5 Each Planning Coordinator shall designate, at least once every five calendar years, the strategic power plants that must comply with Attachment 2a and notify, within 30 calendar days of its designation, each Generator Owner or Transmission Owner that owns facilities[7] in the strategic power plants. *[Violation Risk Factor: Medium] [Time Horizon: Long-term planning]*

M.D.A.5 Each Planning Coordinator shall have evidence that it designated, at least once every five calendar years, strategic power plants in accordance with Requirement D.A.5, Part 5 and shall have dated evidence that each Generator Owner or Transmission Owner has been notified in accordance with Requirement D.A.5, part 5.2. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

[7] Facilities in the strategic power plants include facilities from the generator up to and including the MPT or GSU.

Violation Severity Levels

This Variance adds a VSL for D.A.5 and modifies the VSL for R2 as follows:

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.A.2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable voltage protection so that it does not trip or cease injecting current in accordance with Requirement D.A.2. OR The Generator Owner or Transmission Owner set its applicable voltage protection in accordance with Requirement D.A.2 but, for strategic power plants, failed to do so within 48 months of notification.
D.A.5.	N/A	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2a.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		facilities in the strategic power plants between 31 days and 45 days after its designation.	facilities in the strategic power plants between 46 days and 60 days after its designation.	OR The Planning Coordinator failed to notify, each Generator Owner or Transmission Owner that owns facilities in the strategic power plants or notified them more than 60 days after the its designation.

~~G.~~E. Associated Documents

~~None~~Implementation Plan

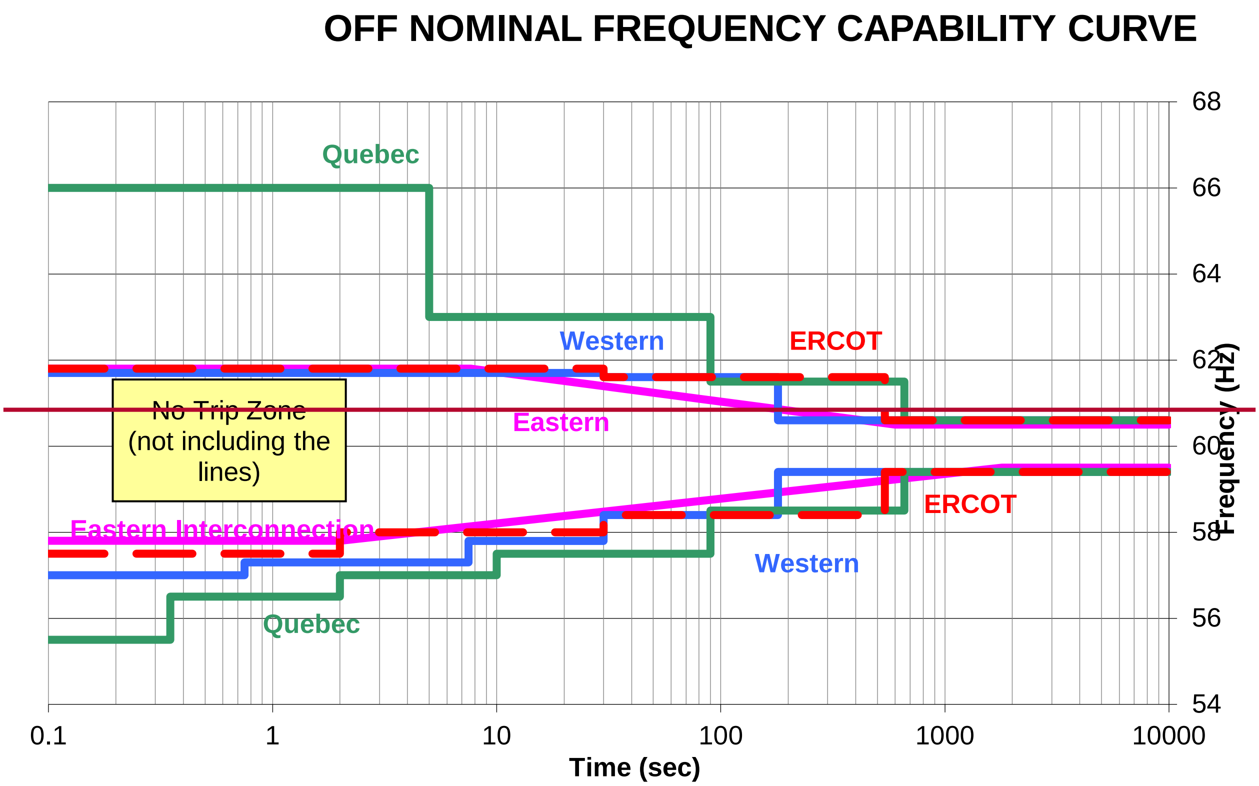
Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.
3	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04

~~H. References~~

1. ~~"The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.~~

~~PRC-024 —~~ Attachment 1



(Frequency No Trip Boundaries by Interconnection[8])

[8] The figures do not visually represent the "no trip zone" boundaries before 0.1 seconds and after 10,000 seconds. The Frequency Boundary Data Points Table defines the entirety of the "no trip zone" boundaries.

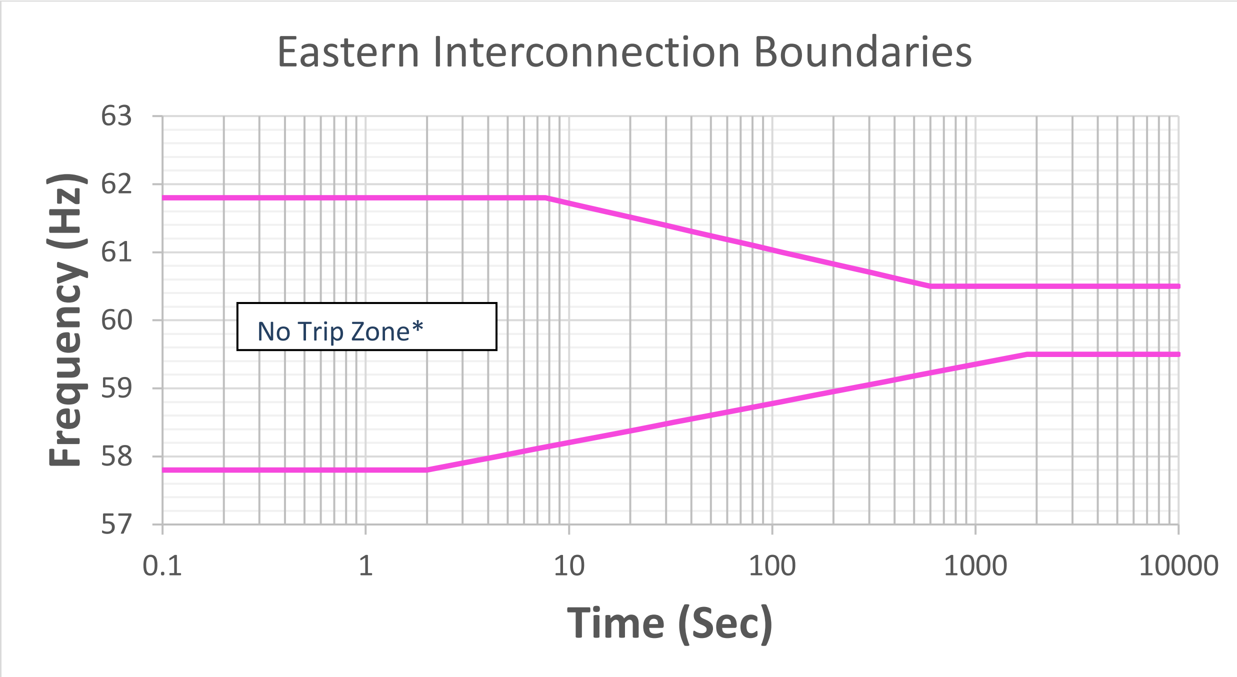


Figure 1

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

~~Curve~~ Frequency Boundary Data Points~~:~~

- Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	Instantaneous[9] ~~trip~~	≤57.8	Instantaneous[9] ~~trip~~
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Table 1

[9] Frequency is calculated over a window of time. While the frequency boundaries include the option to trip instantaneously for frequencies outside the specified range, this calculation should occur over a time window. Typical window/filtering lengths are three to six cycles (50 – 100 milliseconds). Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible.

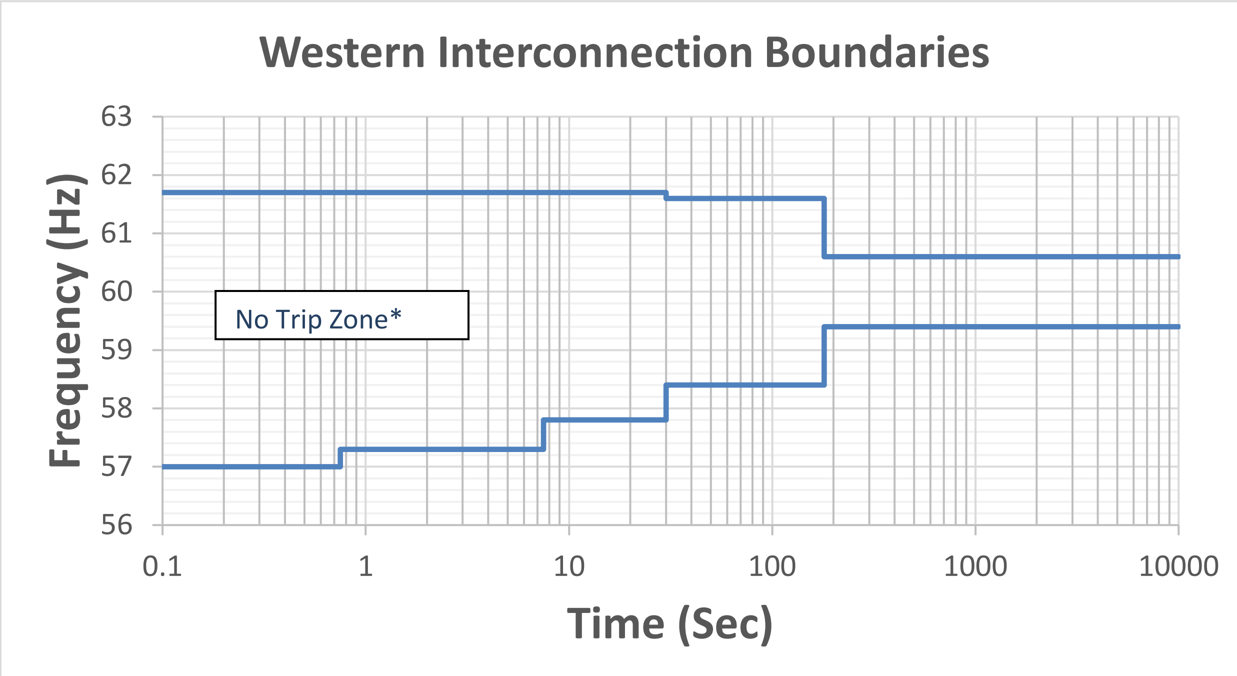


Figure 2

*** The area outside the "No Trip Zone" is not a "Must Trip Zone."**

Frequency Boundary Data Points –Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.7	Instantaneous[9] ~~trip~~	≤57.0	Instantaneous[9] ~~trip~~
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Table 2

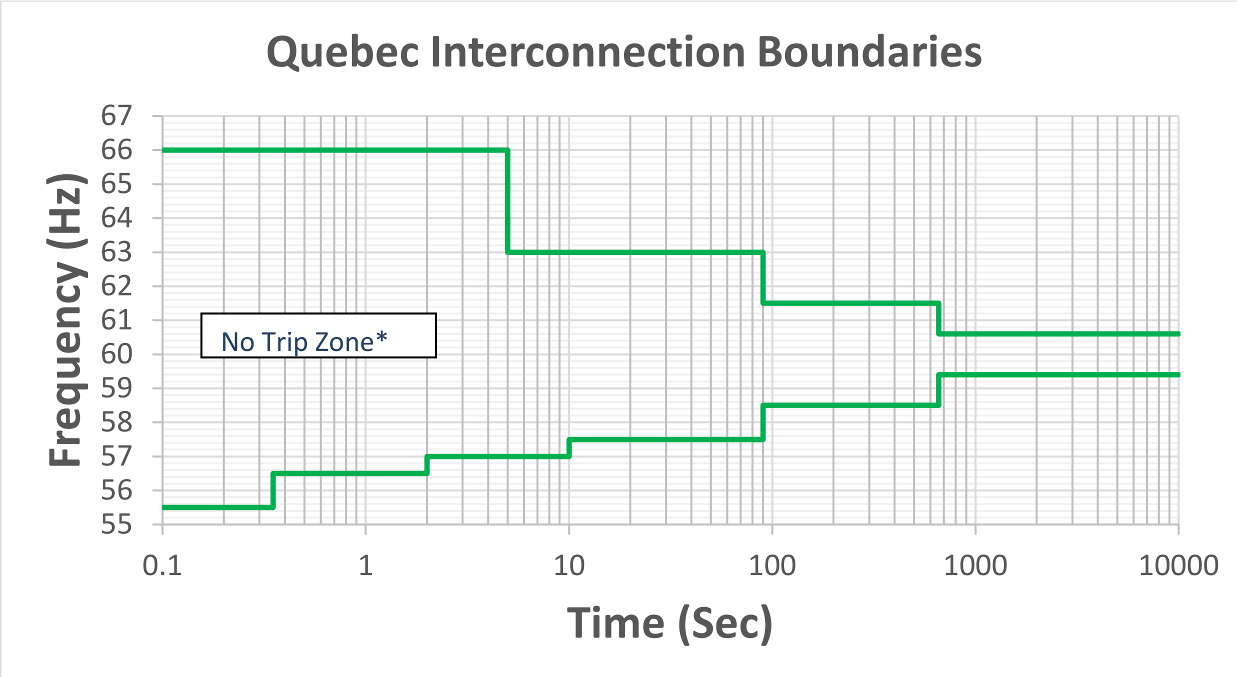


Figure 3

** The area outside the "No Trip Zone" is not a "Must Trip Zone."*

Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (Sec)
>66.0	Instantaneous[9] ~~trip~~	<55.5	Instantaneous[9] ~~trip~~
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

Table 3

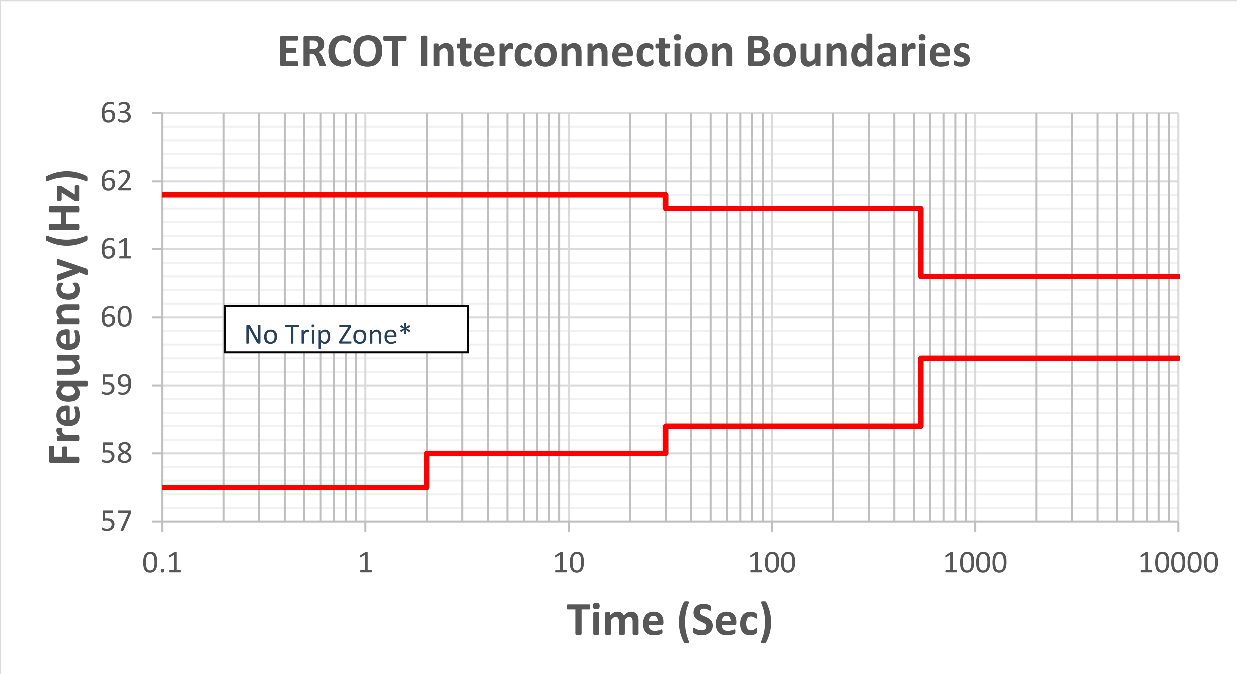


Figure 4

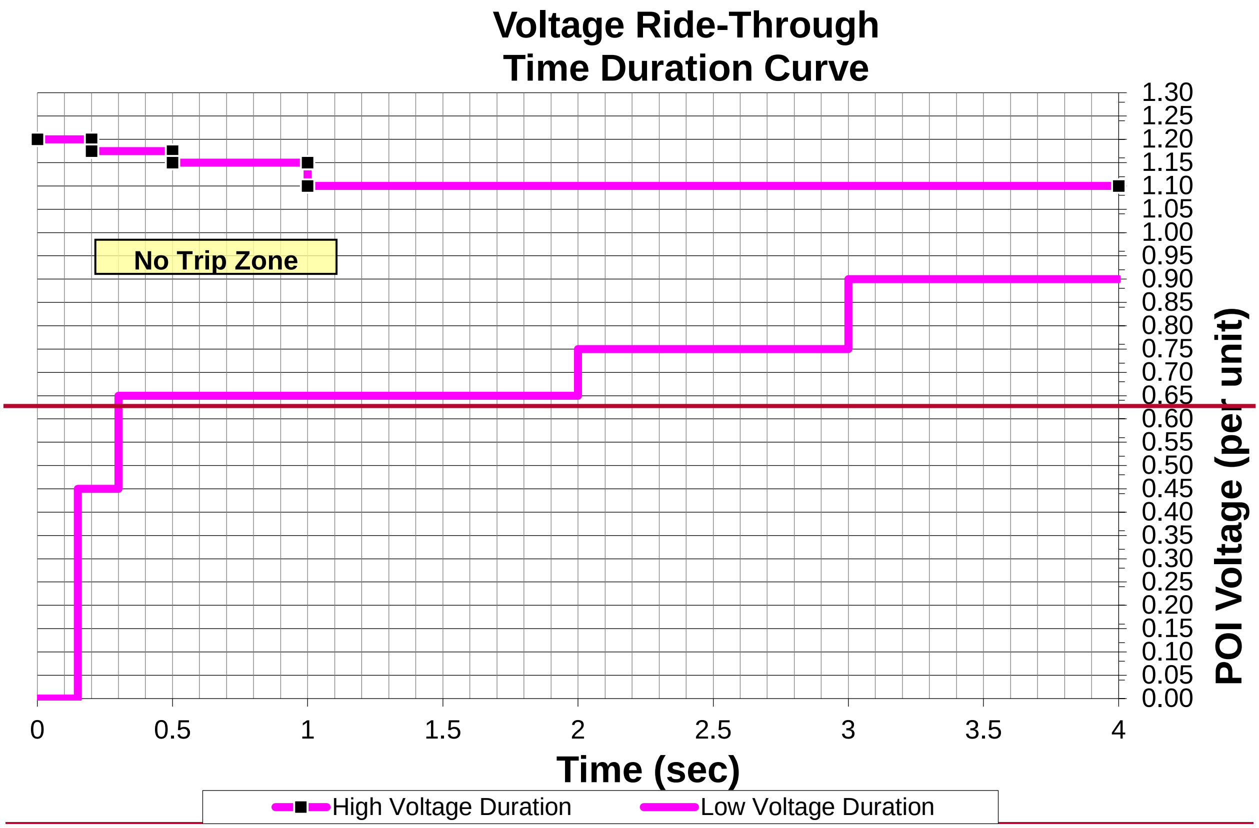
** The area outside the "No Trip Zone" is not a "Must Trip Zone."*

Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	Instantaneous[9] ~~trip~~	≤57.5	Instantaneous[9] ~~trip~~
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 4

~~PRC-024 — Attachment 2~~



~~Ride Through Duration:~~

PRC-024 — Attachment 2
(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)

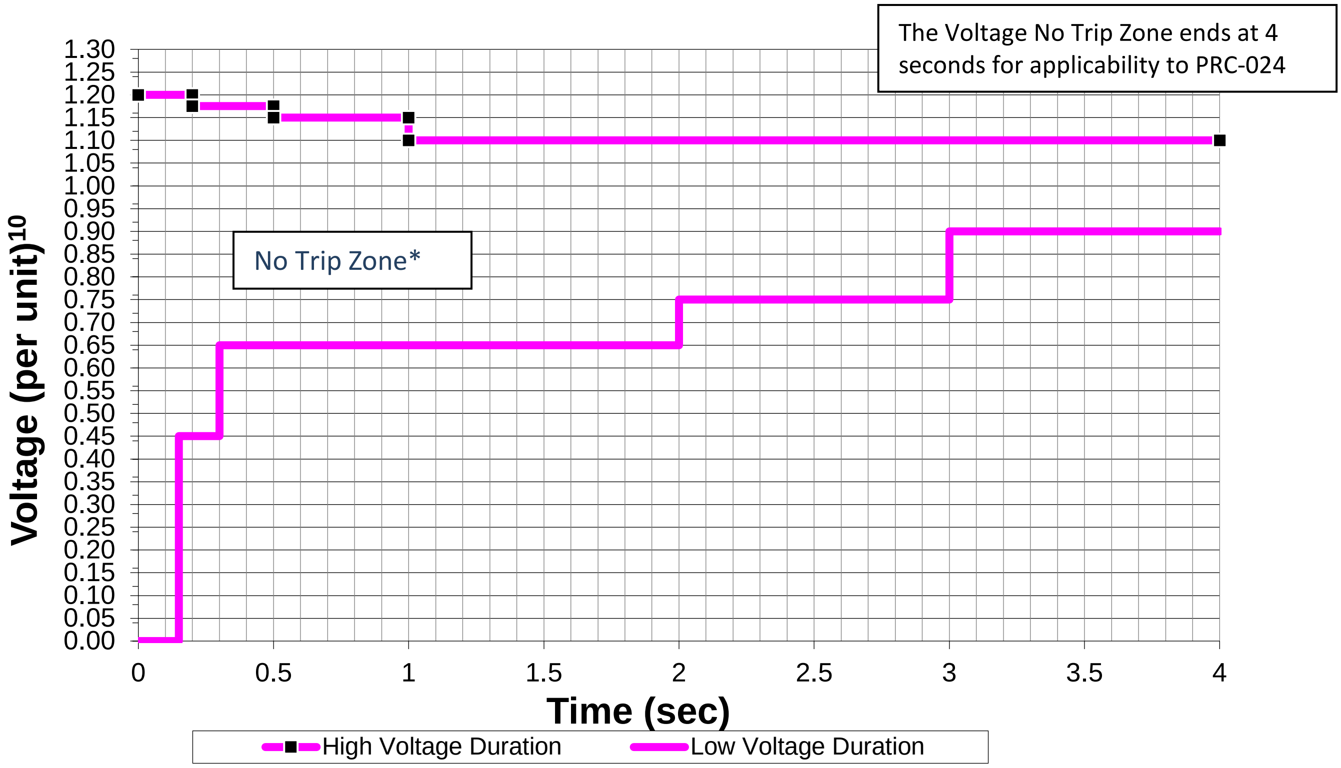


Figure 1

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
≥1.200	0.00	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00
<1.10	4.00	≥ 0.90	4.00

Table 1

[10] Voltage at the high-side of the GSU or MPT.

Attachment 2: Voltage ~~Ride-Through Curve~~Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

~~Curve~~

Boundary Details:

~~1. The per unit voltage base for these curves is the nominal operating voltage~~ Unless otherwise specified by the Transmission Planner ~~in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).~~

~~2.~~1. ~~The curves depicted were derived based on three-phase~~, the per unit voltage base for these boundaries is the nominal transmission system ~~zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.~~voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.).

~~3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.~~

2. ~~The curves depicted~~The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.

~~4.~~3. When evaluating volts per hertz protection, either assume a system frequency ~~is~~of 60 Hertz~~. When evaluating Volts/Hertz protection, you may adjust~~ or the magnitude of the high voltage ~~curve~~boundary can be adjusted in proportion to deviations of frequency below 60 ~~Hz.~~ Hertz.

~~5.~~4. Voltages in the ~~curve~~boundaries assume ~~minimum~~RMS fundamental frequency phase-to-ground or phase-to-phase ~~voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve~~per unit voltage.

5. For applicability to PRC-024, the “no trip zone” ends at 4 seconds.

Evaluating ~~Protective Relay~~Protection Settings:

~~Use either~~The voltage values in the Attachment 2 voltage boundaries are voltages at the high side of the GSU/MPT. For generating resources with multiple stages of step up to reach interconnecting voltage, this is the high side of the transformer with a low side below 100kV and a high side 100kV or above. When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high side of the GSU/MPT. A steady state calculation or dynamic simulation may be used.

If using a steady state calculation or dynamic simulation, use the following ~~assumptions or~~ conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions ~~that are believed to be the most probable~~ for the unit under study ~~to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:~~ .

   ~~b. All of the units connected to the same transformer are online and operating.~~

   ~~c. All of the units are at full nameplate real-power output.~~

   ~~d. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.~~

   ~~e. The automatic voltage regulator is in automatic voltage control mode.~~

b. ~~Evaluate voltage protection relay settings assuming that additional~~All installed generating plant reactive support ~~equipment (such as~~(e.g., static ~~VAr~~VAR compensators, synchronous condensers, ~~or~~ capacitors) equipment is available and operating normally.

c. Account for the actual tap settings of transformers between the generator terminals and the high side of the GSU/MPT.

d. For dynamic simulations, the automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

PRC-024— Attachment 2a

(Voltage No-Trip Boundaries – Quebec Interconnection)

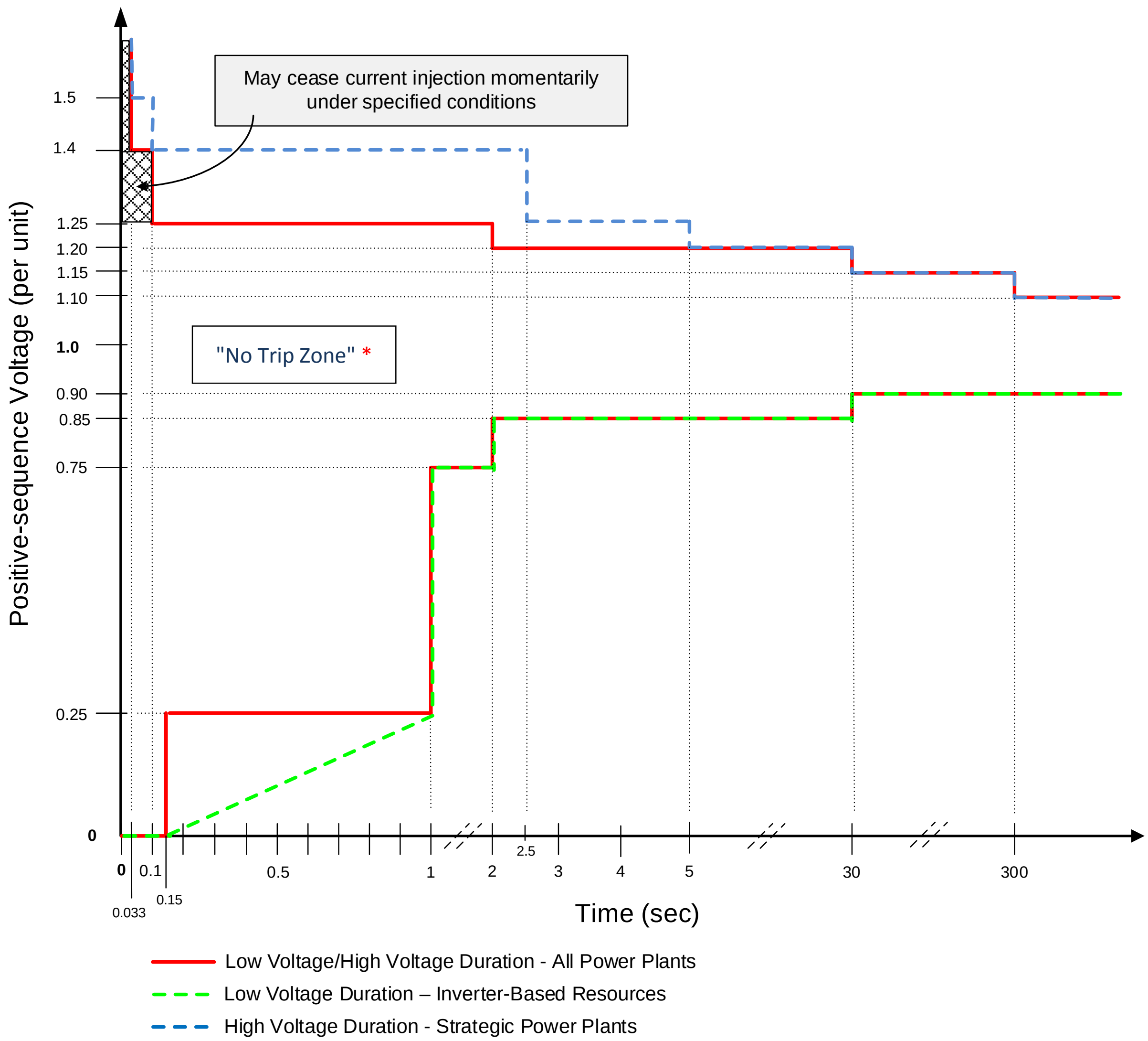


Figure 1

** The area outside the "No Trip Zone" is not a "Must Trip Zone."*

Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Power Plants		High Voltage Duration for strategic Power Plants	
Voltage (pu)	**Minimum Time (sec)**	**Voltage (pu)**	**Minimum Time (sec)**
---	---	>1.50	0.033
>1.40	0.033	>1.40	0.10
>1.25	0.10	>1.25	2.50
>1.20	2.00	>1.20	5.00
>1.15	30	>1.15	30
>1.10	300	>1.10	300
≤1.10	continuous	≤1.10	continuous

Table 1

Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Power Plants		Low Voltage Duration for Inverter-Based Resources	
Voltage (pu)	**Minimum Time (sec)**	**Voltage (pu)**	**Minimum Time (sec)**
<0.25	0.15	<0.25	3.4*V(pu)+0.15
<0.75	1.00	<0.75	1.00
<0.85	2.00	<0.85	2.00
<0.90	30	<0.90	30
≥0.90	continuous	≥0.90	continuous

Table 2

Attachment 2a: Voltage Boundary Clarifications – Quebec Interconnection

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 120 kV, 161 kV, 230 kV, 315 kV, 735 kV, etc.).
2. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
3. When evaluating volts per hertz protection, either assume a system frequency of 60 Hertz or the magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
4. Voltages in the Quebec Interconnection boundaries assume positive-sequence values.

Evaluating Protection Settings:

The voltage values in the Attachment 2a voltage boundaries are voltages at the high side of the GSU/MPT. For generating resources with multiple stages of step up to reach interconnecting voltage, this is the high side of the transformer that connects to the interconnecting voltage. When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high side of the GSU/MPT. A steady state calculation or dynamic simulation may be used.

If using a steady state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the unit under study.
b. All installed generating plant reactive support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
c. Account for the actual tap settings of transformers between the generator terminals and the high side of the GSU/MPT.
d. For dynamic simulations, the automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for Footnotes 2 and 4~~

~~The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.~~